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March 25, 2019

Ms. Kavita Kale
Executive Secretary
Michigan Public Service Commission
7109 West Saginaw Highway
Lansing, Michigan 48917

Re: In the matter of the Application of DTE Electric Company for authority to increase its rates, amend its rate schedules and rules governing the distribution and supply of electric energy, and for miscellaneous accounting authority.
MPSC Case No. U-20162

Dear Ms. Kale:

Attached for electronic filing in the above-captioned matter is DTE Electric Company's Exceptions to the Proposal for Decision. Also attached is a Proof of Service.

Very truly yours,

Andrea Hayden
Digitally signed by Andrea Hayden
Date: 2019.03.25 16:02:16 -04'00'

Andrea Hayden

AH/lah
Enc.
cc: Service List

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of	)	
DTE ELECTRIC COMPANY	)	
for Authority to increase its rates, amend	)	Case No. U-20162
its rate schedules and rules governing the	)	(Paperless e-file)
distribution and supply of electric energy,	)	
and for miscellaneous accounting authority	)	
______________________________________	)	

DTE ELECTRIC COMPANY'S EXCEPTIONS

TO THE PROPOSAL FOR DECISION

Dated: March 25, 2019

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I. INTRODUCTION

On March 6, 2019, the Administrative Law Judge (the "ALJ") issued a Proposal for Decision ("PFD"). DTE Electric Company ("DTE Electric," or the "Company") agrees with the PFD's recommended disposition of some issues. However, the Company believes that other recommendations are based on incorrect or inapplicable analyses, or foundations that do not exist in the evidentiary record as required by the Michigan Administrative Procedures Act ("APA"), and, therefore, submits these exceptions.[1]

DTE Electric attempts to be succinct in light of the Commission's knowledge and prior decisions. Further support for DTE Electric's positions and the reasons for those positions may be found in DTE Electric's Initial Brief and Reply Brief (including Attachments to those briefs), as well as DTE Electric's Application (including Attachments), testimony and exhibits, all of which are incorporated by reference in these exceptions. For consistency and ease of reference, the discussion is presented largely in the order that matters arise in the PFD, and related matters are addressed collectively in the most relevant or logically-sequential context.

It is also important to note that changing one matter can result in corresponding changes to other matters as numbers flow through calculations (for example, the inflation rate affects a number of calculations). Lack of a discussion by DTE Electric to separately address every issue suggested by or consequence resulting from the PFD should not be deemed to constitute an agreement by DTE Electric. DTE Electric, of course, maintains all of its appellate rights.

[1] See MCL 24.285, which states in pertinent part that: "A decision or order shall not be made except upon consideration of the record as a whole or a portion of the record as may be cited by any party to the proceeding and as supported by and in accordance with the competent, material, and substantial evidence."

II. DTE ELECTRIC HAS A $248.6 MILLION REVENUE DEFICIENCY.

DTE Electric initially requested a jurisdictional rate increase of approximately $328.4 million; however, after reviewing Staff's and intervenors' positions, and considering the Commission's December 6, 2018 Order in Case No. U-18150, DTE Electric made eight adjustments in its Initial Brief (listed as items a – h on page 1 of that Brief) and made additional adjustments in its Reply Brief,[2] which resulted in a revenue deficiency of approximately $248.6 million for the projected test year (DTE Electric Reply Brief Attachments A and B).

The PFD recommended a $261,904,000 revenue deficiency including the elimination of the "Credit A" credit approved in Case No. U-20105, which is a $113,667,000 revenue deficiency without consideration of that credit elimination (PFD, pp 223, 301 as corrected by Errata, Attachment A to PFD). For clarity and consistency, the Company's discussion will focus on the PFD's proposed $113,667,000 deficiency. Attachments A and B to these Exceptions reconcile the PFD's $113,667,000 revenue deficiency to the Company's fully-supported revenue deficiency of $248.6 million.

III. DTE ELECTRIC'S RATE BASE IS $17,152,348,000.

DTE Electric's initially-filed rate base was $17,172,558,000, which the Company adjusted to $17,152,348,000 (DTE Electric Reply Brief Attachment A, page 2). Staff recommended a rate base of $17,051,324,000, consisting of $15,572,916,000 of Net Plant and $1,478,408,000 of Working Capital (Staff Initial Brief, pp 4-7; and Appendix B). The Attorney General suggested a $394.8 million reduction in rate base, based on various recommendations reflected on Exhibit AG-23 (AG Initial Brief, pp 74-75).

[2] The additional adjustments include accepting Staff's $4.3 million working capital adjustment related to the active healthcare credit regulatory liability; Staff's $900,000 adjustment to revenues associated with the reduction in the number of RIA customers; and $89,000 decrease to depreciation expense related to the HQ Energy Center.

The ALJ agreed with the Staff and AG on a number of issues and recommended a total rate base of $16,999,569,000 (PFD, pp 106; Attachment B to PFD). DTE Electric takes exception and maintains that its Rate Base for the projected period ending April 30, 2020 is $17,152,348,000.

A. The Company's Fossil Generation capital expenditures are reasonable and prudent and should be approved.

DTE Electric has a two-tiered maintenance and capital expenditure allocation strategy that is based on the anticipated retirement dates of its coal-fired generating units. Belle River and Monroe are the Company's Tier 1 coal-fired units with the greatest long-term value to customers. The remainder of the coal-fired units (St. Clair, River Rouge, and Trenton Channel) are Tier 2 (4T 517, 573). There are different operating performance metric targets that drive the capital and O&M expenditures for each tier of units. Investments in Tier 1 coal units are designed to achieve first quartile reliability performance as measured by random outage factor ("ROF"). Investments in Tier 2 units are limited to those required to maintain safe and environmentally-compliant operations until the units are retired (4T 516-17, 524, 531, 537, 573-74).

1. The Commission should fully approve DTE Electric's Monroe Fly Ash Project Capital Expenditures.

The PFD agreed with the Staff and AG's suggested $34 million disallowance ($9.433 million in the 16-month bridge period, and $24.667 million in the projected test year) for the Monroe Fly Ash Processing project (Exhibit A-12, Schedule B5.1, page 2, line 6).[3] (PFD, pp 36-37). DTE Electric takes exception. Although Staff indicated that it was concerned that "the Company has neither full budgetary approval or a contract for construction of the project" (8T 4190), Staff also recognized that "this project could result in value for both the Company and its

[3] The PFD rejected the AG's proposed disallowance relating to Monroe Power Plant Fly Ash projects based on speculation that the EPA might reconsider and revise the Effluent Limitations Guidelines ("ELG"). (PFD, pp 36-37).

ratepayers and reduce the impact of the Company's generation fleet on the environment" (8T 4191). Company witness Mr. Paul similarly explained that the project is reasonable and prudent because it will provide economic benefits to customers by lowering PSCR costs, as well as environmental benefits through reduction of solid waste (4T 600).[4] Additionally, DTE Electric has received internal project approval and has completed benchmarking and conceptual design of the project. (4T 600) Therefore, the PFD's proposed $34 million disallowance should be rejected.

2. The Commission should approve DTE Electric's capital contingency for the new combined cycle gas turbine ("CCGT") plant.

Non-routine capital investments also include construction costs for the new combined cycle gas turbine ("CCGT") plant. The Commission granted three certificates of need ("CONs") for a 1,100 MW CCGT plant, which is needed due to DTE Electric's pending retirement of Tier 2 coal-fired generating units (April 27, 2018 Opinion and Order in Case No. U-18419). The PFD agreed with the Staff and AG's proposal to disallow $10.5 million of CCGT capital expenditures (contained within Exhibit A-12, Schedule B5.1, page 2, line 30) because they were classified as contingency (PFD, p 31).

The Company disagrees. Ordering paragraph D at page 126 of the April 27, 2018 Opinion and Order in Case No. U-18419 states: "Pursuant to MVL 460.6s(6), the Commission approves $951.8 million for the construction of the natural gas combustion turbine electric generation facilities. This amount includes $934 million for power island equipment and engineering, procurement and construction costs and $17.8 million for contingency costs. Only actual amounts incurred up to $951.8 million shall be recoverable through rates." Mr. Paul explained that because

[4] Mr. Paul's testimony and exhibit regarding unforeseen projects that recently materialized was struck, but the record was preserved through an offer of proof (4T 492-94) and the Company maintains its positions as previously set forth in its filed response and on the hearing record.

the Company is only requesting to recover approximately two-thirds of the total pre-approved project costs (approximately $650 million) in this case, it would be premature to disallow a portion of the approved funding particularly considering that the Company has not exceeded the cost approval provided for in the U-18419 Order. (4T 597-98)

3. The Commission should fully approve DTE Electric's capital and O&M expenditures for River Rouge Unit 3.

The PFD recommends disallowance of capital and O&M expenditures for Rouge Unit 3. The ALJ summarized her decision as follows:

> This PFD finds that the previously deferred capital costs, totaling $8.45 million, that were expended through December 31, 2018, were minimal, reasonably incurred, and should be recovered in rates in the instant proceeding. While issue about the economic operation of RR 3 were raised in the company's previous three rate cases, no specific retirement date for RR 3 was ever evaluated. Thus, MEC/NRDC/SC's recommendation to disallow these costs should be rejected. However, routine capital costs totaling $1.87 million for 2019 through the end of the test year are not reasonable and prudent and should be disallowed. O&M costs for 2019 and the test year should also be disallowed on grounds that the record in this case demonstrates that RR 3 could have, and should have been retired at the end of 2018. (PFD, p 46).

DTE Electric believes that the continued operation of RR Unit 3 through May 2020 was, and remains, justified based on the Company's obligations to provide sufficient and reliable generation to its customers, and is further supported by an NPVRR analysis (summarized on Exhibit A-12, Schedule B6) as well as other factors. DTE Electric agrees with the PFD to the extent that it rejected MEC/NRDC/SC's proposed disallowances through the end of 2018, but takes exception to the PFD's proposed disallowances of capital and O&M costs for 2019 through the end of the test year. As indicated in the quote above, the PFD's proposed disallowances are based on the premise that "RR3 could have, and should have, been retired at the end of 2018" (PFD, p 46). That premise is flawed and cannot support the proposed disallowances because, among other things, DTE Electric has been assigned March 29, 2019 to file an IRP pursuant to

MCL 460.6t, and as the Commission has stated, that IRP proceeding is the proper forum to evaluate plant retirement dates (4T 605-606):

> The Commission agrees with DTE Electric that, although there is a possibility that one or more of the Tier 2 units might retire early, any plans to do so should await the outcome of the Company's 2019 IRP analysis and the results of MISO's Attachment Y reliability study. Other matters such as workforce and local government tax impacts may also be considered in a decision of this magnitude. [April 27, 2018 Opinion and Order in Case No. U-18419, pp 48-49.]

Regardless, the PFD proceeded to address the question of when RR 3 should be retired in this case, and to answer that question based on the ALJ's opinion on the likelihood of MEC/NRDC/SC's economic analysis turning out to be correct (See, for example, PFD, p 47: "Through the testimony of Mr. Allison and Mr. Fagan, MEC/NRDC/SC convincingly showed that the economics of operating RR3 until the end of the test year is more likely than not to be detrimental to ratepayers and that there is a significantly greater benefit to retiring the unit in December 2018"). [5]

Instead, the question in this case is whether the projected costs associated with the operation of RR Unit 3 are reasonable and prudent, and the answer to that question involves more than just an economic analysis. The Company also evaluates factors including the age and condition of the generating unit, resource adequacy, grid reliability, local community impacts, and workforce planning when determining whether a generating unit should be retired and the timing of that retirement (4T 525-31, 576-77). MISO's permission is also needed to retire units pursuant to the Attachment Y process (4T 526-27). Since the Tier 2 units comprise nearly 2,000 MW of net

[5] An agency decision may not be based on speculation. *Ludington Service Corp v Comm'r of Insurance*, 444 Mich 481, 483, 494-97, 500-501, 507; 511 NW2d 661 (1994), *amended* 444 Mich 1240 (1994) (unanimously reversing agency decision that exceeded the limits of the agency's statutory authority, and that was based on speculation instead of the required competent, material and substantial evidence); *In re Complaint of Pelland,* 254 Mich App 675, 685-86; 658 NW2d 849 (2003).

summer capability, it is reasonable and prudent to facilitate a phased transition between now and 2023 (as indicated above) to maintain a safe and reliable supply of energy for customers (4T 524).

MEC/NRDC/SC's economic criticisms were also overstated. The Company's NPVRR analysis for RR Unit 3 consisted of two options (1) operate RR Unit 3 until the planned retirement date in May 2020, or (2) retire RR Unit 3 as soon as practical, which – at the time the NPVRR analysis was conducted – was December 31, 2018, after the Company complies with MISO's required retirement request filing process (3T 367).

Three sensitivities for capacity price were examined to capture the range of uncertainty with capacity prices. The NPVRR results ranged from $15 million more costly to $10 million less costly to maintain the planned 2020 retirement date. This range of sensitivity outcomes supports continued operation of RR Unit 3 as the most reasonable and prudent option, as further discussed below, and considering the non-economic factors outlined above and recognized by the Commission in Case No. U-18419 (3T 369, 373-77; Exhibit A-12, Schedule B6, p. 2, column (c)).

The PFD also appears to have been persuaded by MEC/NRDC/SC witness Mr. Allison's identification of an adjustment in the NPVRR analysis (PFD, pp 41-42); however, as Ms. Dimitry pointed out in her rebuttal testimony, his adjustments still yielded a mixed range of outcomes. Given the mixed range of financial outcomes (even after Witness Allison's adjustments), the other non-economic considerations discussed by Witness Paul support continued operation of RR3 at this time, along with the requested nominal capital investments and O&M to ensure that such operations are maintained safely (3T 377-378).

As discussed above, there are additional factors to consider when determining whether to retire a generating unit, and the Company decided that the best option for its customers is to continue operating RR Unit 3 until its planned retirement date in 2020 (3T 369, 379-80; 4T 524-

31, 575-76). Further justification for continued operations of RR Unit 3 until May 2020 is provided by the MISO Attachment Y reliability study report for RR Unit 3, which indicates that retirement or suspension of RR Unit 3 may create thermal or voltage issues that could require the Company to shed firm load to ensure grid reliability (Exhibit MEC-43). Firm load shedding is essentially a technique of last resort to avoid overloading a system, where power would be cut off for some customers, above and beyond those customers that chose to be on an interruptible tariff, to maintain system availability for other customers. The Company has significant concerns about relying on this type of electrical service interruption to customers as means to ensure electric system reliability. Maintaining and operating RR Unit 3 until its planned retirement date will provide time to identify and implement alternative solutions that can ensure continued reliable service to customers (4T 528, 577, 660).

The PFD states: "This PFD agrees with DTE Electric that shedding firm load is not a reasonable option for dealing with grid stability, but the company has had years to devise a solution for this potential problem, and it has failed to do so" (PFD, pp 47-48. Emphasis in original). The PFD's criticism is unfounded. The ultimate solution to the planned loss of Tier 2 capacity is to replace it, which DTE Electric is doing in part with the new CCGT plant, and through its otherwise systematic and well-planned Tier 2 retirement schedule and other activities. The Commission previously agreed with DTE Electric that "the most reasonable and prudent course of action is to retire the Tier 2 units by 2023 as DTE Electric proposes" and that "although there is a possibility that one or more of the Tier 2 units might retire early, any plans to do so should await the outcome of the company's 2019 IRP analysis and the results of MISO's Attachment Y reliability study" (April 18, 2018 Order in Case No. U-18419, pp 47-49). The Company proactively submitted an Attachment-Y Suspension request to MISO on January 18st, 2018 to study the effects of retiring

RR Unit 3 in 2020 and did not receive the final results from this study until March 20th, 2018. As such, the Company has not had years to devise a solution as the PFD suggests and near term electrical system planning and operation is dynamic (4 T 526-528).

MEC/NRDC/SC also relied on their witness Mr. Fagan who suggested the disallowance of projected capital expenditures for the River Rouge and St. Clair power plants because MISO Attachment Y studies indicate that they are not needed as System Support resources (6T 2535-36). Mr. Paul explained that this suggestion should be rejected because the MISO Attachment Y analysis for RR Unit 3 assumed a 2020 retirement, and the St. Clair analysis assumed a 2022 retirement. No analysis has been completed based on any other retirement date, and MISO would need six months to perform additional Attachment Y studies (4T 603-604). Mr. Fagan also ignored other factors that determine the reasonableness and prudence of continued operations of a generating unit, as indicated above (4T 525, 604) and recognized by the Commission. April 27, 2018 Opinion and Order in Case No. U-18419, pp 48-49 (quoted above).

The PFD correctly rejected MEC/NRDC/SC's proposed disallowance of capital expenditures for the St. Clair units, explaining in part: "Because DTE Electric is expected to file an IRP within a month, the issues raised by MEC/NRDC/SC concerning the economics of retiring St. Clair units and Trenton Channel earlier than planned should be addressed as part of that proceeding, as the Commission has directed" (PFD, p 49). The PFD is correct, and should have applied this same correct reasoning to RR 3. The PFD's only explanation for not doing so is: "These units are not currently expected to retire for three years or more, thus they are not similarly situated to RR 3" (PFD, p 49).

The Commission was well aware that DTE Electric's Tier 2 units were scheduled for retirement between 2020 and 2023 (see, for example, April 18, 2018 Order in Case No. U-18417,

p 30), but the Commission treated all of the Tier 2 units collectively, as indicated above. There is no sound basis to deviate from the Commission's recent Order and instead now carve out RR 3 for special treatment as the PFD suggests.

With respect to DTE Electric's Trenton Channel and St. Clair plants, the PFD states:

> Although this ALJ does not recommend deferral or disallowance of capital costs at this time, given that all aspects of the retirement of these units will be addressed in the IRP, the issue of cost recovery for these units should nevertheless be included in the company's next rate case, and the company should be directed to submit an up-to-date NPVRR for the St. Clair and Trenton Channel units" (PFD, p 49).

DTE Electric disagrees that the Company should be required to essentially litigate the same issues in multiple cases, with potentially different outcomes. As the PFD initially observed, "all aspects of the retirement of these units will be addressed in the IRP." The PFD's suggestion that the Commission should instead act inconsistently threatens an illegal result. *Application of Michigan Consolidated Gas Co*, 304 Mich App 155, 173; 850 NW2d (2014) (vacating reconciliation orders because MPSC "acted unreasonably, or capriciously" in setting a prospective pricing change, then applying that change retroactively); *Michigan Gas Utilities v Public Service Comm*, 200 Mich App 576, 584-85; 505 NW2d 27 (1993) (rejecting MPSC attempt to disavow its prior decision, explaining that if an estoppel existed, it was against the MPSC).[6]

Mr. Paul explained that Mr. Allison's proposal to disallow recovery of future capital costs related to RR Unit 3 lacked merit for the reasons indicated above regarding Mr. Fagan's flawed proposal (4T 605-606). Ms. Dimity agreed (3T 379-80), and further explained that Mr. Allison

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[6] *See also, St. Cloud Public Service Co v St. Cloud*, 265 US 352, 363 (1924) (gas company and rate setting entity entered into a contract fixing rates); *Wiersma v Michigan Bell Telephone Co*, 156 Mich App 176, 185; 401 NW2d 265 (1987) ("The state, as well as an individual, may be estopped by its acts, conduct, silence and acquiescence"); *Entergy Gulf States, Inc v Louisiana Public Service Comm*, 730 So2d 890, 901 (1999), reversing Public Utility Commission's attempt to preclude a utility from recovering certain expenses as "untenable" and finding all its reasons to be "arbitrary or capricious or unsupported by the record." 730 So2d at 901.

improperly focused on what he considered to be the most likely scenario, while dismissing other sensitivities, which is not a reasonable and prudent basis for making power plant retirement decisions. In contrast, the Company considered an appropriate range of capacity price sensitivities in its RR Unit 3 economic analysis to capture the range of uncertainty in capacity prices, as indicated above. Moreover, the June 2018 PACE capacity price forecast was the most recent available and appropriate for a low forecast of capacity prices. The Cost of New Entry ("CONE") represented an appropriate upper boundary for capacity prices in MISO. The 50% of CONE sensitivity represented a very reasonable middle range sensitivity, which closely compares to capacity prices paid by the Company in 2017 and the recent November 2018 PACE capacity price forecast (3T 374-75). The change in PACE capacity forecasts from June 2018 to November 2018 further supports the Company's consideration of a full range of sensitivities, and demonstrates the unreasonableness of Mr. Allison's focus on what may appear to be most likely at one point in time (3T 376).

Even if one were to give some credence to Mr. Allison's views (which would be inappropriate), there are still non-economic considerations – including concerns about reliability – that support continuing operation of RR Unit 3 at this time, along with the requested nominal capital and O&M to ensure that those operations are maintained safely. These non-economic factors become even more important in cases like this where economic analyses yield mixed or marginal outcomes. It simply would not be reasonable or prudent to make long-term decisions regarding capital intensive assets every time an economic analysis suggests a shift in value (3T 377-78). Proposed cost disallowance (to effectively force immediate retirement) is also contrary to the Commission's recent conclusion that any early retirements should await the outcome of the

Company's IRP, and that non-economic factors may be considered when contemplating an early retirement of Tier 2 units such as RR Unit 3 (3T 379-80).

Ms. Dimitry explained that the decision to retire a generating unit earlier than planned requires diligent analysis using comprehensive and internally-consistent data, and must be supported with specific reliability studies under MISO's Attachment Y process, as outlined above and recognized by the Commission in its April 27, 2018 Order in Case No. U-18419. Unless and until such a comprehensive analysis is completed (as is planned for the Company's IRP to be filed March 29, 2019) it is reasonable and prudent for the Commission to approve the recovery of capital and O&M investments to ensure the continuing safe operations of Tier 2 plants through their current retirement dates (3T 380-81).

The PFD also appears to have been persuaded by MEC/NRDC/SC's suggestion that the capacity-related reliability need, and the capacity value of Tier 2 units, are unclear (PFD, p 47). To the contrary, the record includes an extensive discussion by Mr. Arnold regarding capacity market fundamentals and how local resources like the Company's Tier 2 plants support MISO Zone 7 (where DTE Electric's service territory is located) meeting the MISO Zone 7 Local Clearing Requirement ("LCR"), which has both economic and reliability benefits (3T 296-302). The future is, of course, inherently unclear (as demonstrated by changing capacity predictions over time), but this favors a conservative approach to plant retirements, contrary to the PFD's recommendation.

More specifically, the Local Reliability Requirement ("LRR") and Capacity Import Limit ("CIL") are directly used to calculate the LCR (the amount of capacity needed in a MISO zone to meet the NERC reliability standard of a one-day loss of load event every 10 years). From Planning Year ("PY") 2018/2019 to 2019/2020, the MISO Zone 7 per-unit LRR increased from 115.3% to

117.2% of zonal coincident peak demand, and the MISO Zone 7 CIL dropped from 3,785 MW to 3,211 MW. This situation results in a need for more local resources to meet the NERC reliability standard, holding all else constant (3T 296-97). Applying the PY 2019/2020 MISO Zone 7 per-unit LRR and CIL values to the 2017 Capacity Demonstration indicates that MISO is 1% away from not meeting the LCR in 2021/2022 (3T 298). MISO Zone 7 not meeting the LCR would result in the MISO Zone 7 Planning Reserve Auction ("PRA") clearing price for capacity being set to the Cost of New Entry ("CONE," which will be $88,830 / Zone 7 Zonal Resource Credit in the 2019-2020 PRA). For approximately 670 MWs of unforced capacity (the size of St. Clair Units 1, 2, 3 and 6) that the Company is short to its planning requirement, the Company's customers would pay approximately $60 million in any Planning Year that MISO Zone 7 is short to the LCR (3T 299).

Mr. Allison argued that excess capacity can be expected based on June and September 2018 PACE forecasts (6T 2621-23). This suggestion is based on outdated information. MISO posted the 2019/2020 LOLE Study Report in October 2018, after the June and September 2018 PACE forecasts were developed, and Mr. Allison's discussion does not include the recent increase in MISO Zone 7 LRR and decrease in MISO Zone 7 CIL (3T 301). Mr. Allison's heavy reliance on out-year forecasts is also inappropriate because the future is uncertain. For example, MISO's 2017 LOLE Study Report forecasted the Zone 7 PY 2019/2020 per-unit LLR would be 113.2%, but the actual Zone 7 PY 2019/2020 per unit LRR is 117.2% - a 4% increase in 2 years (3T 300).[7]

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[7] MEC/NRDC/SC witness Mr. Fagan similarly relied on out-year forecasts. He used the 2019/2020 and 2024/2025 MISO Zone 7 LRR values from the 2019/2020 LOLE forecast to indicate MISO Zone 7 will have increased headroom and the transmission system will be relatively unconstrained for exchanging capacity (6T 2535, 2537, 2539). These claims are founded on the assumption that MISO's out-year forecast will turn out to be accurate, which is speculative as indicated above regarding the recent 4% (from projected to actual) increase in per-unit LRR. MISO has also recommended discontinuing out-year forecasts due to volatility and changing variables. Mr. Fagan's further discussion of potential developments (including transmission projects) beyond the planned retirement dates lacks relevance (3T 301-302).

Resource adequacy concerns are a significant consideration in the retirement of RR 3. The numbers are a moving (and therefore uncertain) target, and the Company's decision-making cannot be judged based on speculation [8] or hindsight. As the Court explained in *Detroit Edison Co v Public Service Comm*, 261 Mich App 448, 452; 683 NW2d 679 (2004) (reversing the MPSC's attempt to use hindsight to determine whether DTE Electric could recover its costs), the utility "does not have the benefit of hindsight in accruing costs, and the PSC must review the utility's expenditures in light of the knowledge that was available at the time the expenditures were made."[9] The Commission should recognize the capacity-related reliability need and capacity value of Tier 2 plants, and continue to approve rate recovery of future capital costs to support local capacity needs in Michigan's lower peninsula (3T 302).

Therefore, the PFD's proposed disallowance of $1.87 million of RR 3 routine capital costs for 2019 through the end of the test year should be rejected.

In addition to capital, the PFD also recommends that "O&M costs for 2019 and the test year should also be disallowed on grounds that the record in this case demonstrates that RR3 could have, and should have, been retired at the end of 2018" (PFD, p 46. See also, p 138, which identifies

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[8] *Ludington Service Corp v Comm'r of Insurance*, 444 Mich 481, 483, 494-97, 500-501, 507; 511 NW2d 661 (1994), *amended* 444 Mich 1240 (1994) (unanimously reversing agency decision that exceeded the limits of the agency's statutory authority, and that was based on speculation instead of the required competent, material and substantial evidence); *In re Complaint of Pelland*, 254 Mich App 675, 685-86; 658 NW2d 849 (2003).

[9] *See also, ABATE v Public Service Comm*, 208 Mich App 248, 260; 527 NW2d 533 (1995) (rejecting challenge to utility's cost recovery as "inconsistent with the prudent investment test under which the end result of a utility's efforts do not determine how much is recoverable. Rather, utilities are compensated for prudent investments at their actual costs when made regardless of whether the investments are deemed necessary or beneficial in hindsight."); *RRC v Public Service Comm*, 198 Mich App 144, 151; 497 NW2d 558 (1993) ("The reasonable utility management test for prudence is whether the costs in question are those a reasonable utility manager would have incurred, in good faith, under the same circumstances and at the relevant point in time. Under this test, the fact that a management decision turns out to have been wrong in hindsight is not relevant."); *Consumers Energy Co v Public Service Comm*, 261 Mich App 455, 460; 683 NW2d 188 (2004) ("An approval made contingent on future unknown facts that may indeed eradicate the initial approval is not a provision for full recovery.").

the proposed O&M disallowance as $17.7 million). The PFD offers no further explanation, but notes that the Commission "approved full recovery of O&M costs" in Case No. U-18255 (PFD, p 46, n 61).

The PFD's proposed O&M disallowance should be rejected. In addition to the discussion above, the PFD's proposal is contrary to the Commission's decisions in Case No. U-18255, where the Commission approved operational expenses. On rehearing, the Commission further approved maintenance expenses, explaining in part:

> The Commission approved approximately $6.1 million in operational expenses (out of a total O&M request of $15.536 million), but disallowed all maintenance expenses, amounting to $9.173 million . . .The Commission agrees with the utility that, while the unit is in use, reasonable and prudent maintenance costs should be approved to ensure safe operation and a smooth transition to retirement. (June 28, 2018 Order on Rehearing in Case No. U-18255, p 6).

Additionally, as noted above, the Commission agreed that any plans to retire the Tier 2 units early "should await the outcome of the company's 2019 IRP analysis and the results of MISO's Attachment Y reliability study" (April 18, 2018 Order in Case No. U-18419, pp 47-49). The same reasoning applies here, and so the PFD's contrary recommendation should be rejected.

4. The Commission should approve the Ford combined heat and power ("CHP") plant.

The PFD recommended that capital costs associated with the Ford CHP plant should be disallowed because DTE Electric did not demonstrate compliance with the Code of Conduct (PFD pp. 58-59). The Company takes exception to this recommendation because the record demonstrates that the price to be paid by DTE Electric for the CHP plant is at or below market price as required by the applicable code of conduction provisions. The Code of Conduct provides:

> If an affiliate or other entity within the corporate structure provides services or products to a utility, and the cost of the service or product is not governed by section 10ee(8) of 2016 PA 341, MCL 460.10ee(8), compensation is at the lower

of market price or 10% over fully allocated embedded cost. [Mich. Admin Code R 460.10108(4)]

In order to determine a market price for the CHP plant, DTE Electric retained HDR to develop an independent cost estimate. This estimate was obtained before the Company received DTE Power and Industrial's ("P&I") cost estimate and it was used to inform negotiations with P&I. HDR calculated the cost at $84.6 million, hence, the $62.3 million purchase price was determined to be a reasonable and prudent price that is significantly below the estimated market price (5T 1130, Exhibit A-28, Schedule R2)). Additionally, the levelized cost of energy ("LCOE") analysis for the CHP plant demonstrates that it is in a competitive range with alternative generation technologies such as solar, wind and combined cycle natural gas (5T 1131). As such the HDR study was a valid indicator of market price.

Nevertheless, to further address concerns regarding transparency, the contracts related to the transaction with P&I were also provided to the parties. (Confidential Exhibit A-40, Schedules DD-1 through DD-8) Those contracts set forth the numerous details regarding the CHP plant itself (schematics, diagrams, spreadsheets, etc.) and the deal structure between DTE Electric and its affiliate. While MEC/SC/NRDC witness Mr. Sansoucy raised concerns that the HDR estimate was not an "apples-to-apples" comparison because DTE Electric did not provide a cost breakdown from DTE P&I for the project, a review of the contract materials provides detailed information regarding the plant construction. (See Confidential Exhibit A-40 Schedule DD-4)

In addition to the above, the Company obtained and disclosed the supporting documents that HDR utilized to prepare its cost estimate, which included estimates from multiple equipment vendors. (Confidential Exhibit A-40, Schedule DD-8) No party pointed to any specific concerns regarding these documents. In fact, the parties appear to disregard the contracts and the supporting documents in their recommendations. Mr. Coppola's transparency argument cited in the PFD

rests solely on the premise that the Company should have acquired competitive bids and ignores the remainder of the evidence provided by the Company.

MEC/SC/NRDC also argue that the Company did not provide sufficient evidence that the cost of the CHP plant was at or below market price. However, neither MEC/SC/NRDC nor the AG provided any substantive criticisms of the HDR cost estimate aside from the fact that it seems too high. They suggest that the only satisfactory evidence of market price is alternative bids. The PFD agrees that the HDR cost study was not sufficient to demonstrate compliance with the Code of Conduct, although notes that the Company could find alternative means aside from alternative bids to show that the cost is market based. (PFD p. 59, fn 54) The Code of Conduct does not specify a particular method to determine market price, and Staff and the PFD inherently recognize this by suggesting that alternative means could be utilized to demonstrate compliance. Based on the extensive documentation provided by the Company to support the CHP plant's cost and the transaction with DTE P&I, the recommendation to disallow capital costs associated with the CHP plant should be rejected.

The PFD also cites MEC/SC/NRDC's argument that HDR's indirect costs (vs direct costs) appear to be excessive (PFD p. 55) However, even when the $14 million contingency highlighted by Mr. Sansoucy is removed, HDR's estimated project cost is still 70.6 million. In Mr. Sansoucy's testimony cited in the PFD he also suggests that valid site construction cost estimates of approximately $12.5 million and engineering and insurance costs of $4.6 million and $2.7 million should be disregarded, without any justification (PFD p. 55). But even going one step further for argument's sake and discounting these costs generously by one-third, the total estimated cost for the plant is $63.8 million. Additionally, Mr. Sansoucy's argument that the Commission should

consider costs associated with the gas pipeline is not applicable here as it will not be an expense of DTE Electric and subject to review in future DTE Gas rate cases (5 T 1142).

Finally, Mr. Coppola's characterization of the Ford requests for proposals, as cited in the PFD (p. 57), is incorrect. Ford did not seek to own their own CHP plant, but instead requested that DTE Electric provide an integrated solution for the central energy plant as part of the RFP process (5T 1129).

It also bears consideration that there does not appear to be any significant dispute among the parties regarding the benefits retained by DTE Electric as a result of this project. Nevertheless, the PFD's recommendation disregards the substantial benefits that the Company and its customers receive by retaining DTE Electric's largest bundled customer. The Company estimates that it will retain over $7M in annual revenue by completing the project, or $102.1 million on a net present value basis over the 30-year life of the facility. This positively impacts affordability for all of the Company's customers. (Exhibit A-28, Schedule R1) Thus, taken as a whole, the evidence provided by DTE Electric in this case shows that the CHP plant is a reasonable and prudent cost that should be approved.

B. The Commission should approve DTE Electric's Distribution Operations capital expenditures.

DTE Electric supported Distribution Operations ("DO") capital expenditures of $651.4 million in 2017, which are projected to be $810.2 million for 2018, $285.6 million for the four months ending April 30, 2019, and $830.6 million for the projected test year 12 months ending April 30, 2020. Staff proposed disallowances for 2018, the four months ending April 30, 2019, and the test year. The PFD agreed with Staff's proposed disallowances corrected for an inflation

adjustment (PFD, pp 71, 76). The Commission should instead reject the proposed disallowances as discussed below.

1. The PFD's proposed 2018 disallowance should be rejected.

Staff initially proposed a $64,455,000 disallowance for 2018, based primarily on Staff applying its forecasting methodology to actual spending from January to August 2018 (8T 4117). The Company responded by explaining that Staff's proposal should be rejected for three primary reasons, including that Staff applied its forecasting methodology inconsistently, and arbitrarily assumed that no additional capital replacements would be required for Storm from September through December 2018,[10] despite the Company experiencing an average of seven storms between September and December in recent years (Exhibit A-23). In September and October 2018 alone there were four storms and the monthly Emergent Replacement spending has exceeded $32 million per month, which is well above the five-year average of $16.8 million per month (4T 838-845). Staff then modified its position to a recommended $19,223,000 disallowance, stating that "Staff agrees with all of the forecasts [shown by Exhibit A-31, Schedule U-7, reflecting actual spending as of October 31, 2018] except for the projection for Emergent Replacements" (Staff Initial Brief, p 39). The PFD agreed (PFD, p 71).

The Company disagrees with the proposed disallowance because the problem indicated above persists when arbitrarily proposing special treatment for Emergent Replacements. Staff offered the following reasoning for its proposed disallowance:

> The Company spent $297,370,000 on emergent replacements from January through October 2018. Using the straight-line extrapolation methodology (multiplying by 12/10 or 1.2), the total spending in this category would be $356,844,000. (Exhibit A-31, Schedule U-7). This amount is simply too high and

[10] For example, Staff stated that: "Storm, the sub-category with the highest YTD actual spending, was determined to be the sub-category where spending stops" (8T 4115).

> assumes that the higher-than-forecasted spending in Emergent Replacements will continue in November and December. [Staff Initial Brief, p 40.]

The Company disagrees and maintains that the forecasts (which Staff acknowledged are appropriate for all other categories) should be applied consistently. Moreover, there is no evidentiary support for Staff's assumption that storm-related costs would suddenly drop off in November and December of 2018. The record indicates that 2018 was a particularly stormy year, and that historically, November and December storms are commonplace (Exhibit A-23; 4T 838-845). The Commission should not disregard appropriate forecasting and record evidence based on Staff's belief (apparently shared by the PFD at p 71) that the result is *"simply too high*." Therefore, the PFD's recommended disallowance should be rejected.

2. The PFD's proposed disallowances for the four months ending April 30, 2019, and the Test Year should be rejected.

Staff initially proposed a $31,447,000 disallowance for the first four months of 2019 (8T 4119), and a $61,894,000 disallowance for the projected test year (8T 4121). Staff revised its recommended disallowance to $21,912,000 for the first four months of 2019, and $33,053,000 for the test year (Staff Initial Brief, p 42). The PFD agreed with Staff's proposed disallowances, but did recognize the Company's adjustment to include 2019 inflation as calculated in DTE Electric's reply brief (PFD, p 76, referencing the calculations set forth above). However, the Company maintains that no disallowance is warranted.

First, Staff used its 2018 forecast to develop its 2019 and 2020 forecasts (Staff Initial Brief, p 42). However, as explained above, Staff's 2018 forecast is improper because it arbitrarily under-forecasted emergent replacements. Since Staff used a flawed starting point for its analysis, the result is similarly neither reasonable nor prudent (4T 850-51).

Second, Staff did not consider the merits of the Five-Year Plan, and instead simply used historical costs (plus inflation[11]) to forecast future capital expenditures (Staff Initial Brief, p 43). There are some cost categories where it is appropriate to use historical costs plus inflation to estimate future expenditure, but not all categories are a good fit for this forecasting methodology. For example, when there are planned spending increases beyond inflation, using this methodology will cause under-forecasting. This methodology is particularly inapt when applied to a category where the Commission has ordered the Company to reexamine its spending and focus on a five-year plan to address reliability issues (MPSC Case No. U-18014, 10/11/17 Order). Staff's methodology ignores the fact that the Commission has asked DTE Electric to do things differently – and the Company has developed a plan to do just that. Staff's plan would return the Company to the status quo, which does not address the Commission's concerns, nor does it produce satisfactory safety and reliability improvements. DTE Electric's DO investments are guided by the Five-Year Investment and Maintenance Plan ("Five-Year Plan," Exhibit A-23, Schedule M5) that the Company developed based on a careful evaluation of asset conditions and customer needs. With the goal of reducing risk, improving reliability and managing costs, the Company evaluated a broad portfolio of investments and prioritized them based on their ability to meet goals that are in the best interest of customers (4T 704, 812). Staff's overly simplistic methodology also stands in sharp contrast to the significant concerns and substantial effort reflected in the Five-Year Plan (4T 850-52). Mr. Bruzzano explained that using a historical "costs plus inflation" methodology essentially sets aside the Five-Year Plan:

> The Company spent a great deal of effort to develop the Five-Year Plan and determine what is needed to improve reliability, reduce risk and manage costs as directed by the Commission in Case No. U-18014 (which was later moved to Case No. U-20147). The Company collaborated with the Staff in this effort. Solely

[11] Staff did not apply inflation consistently; this concern is addressed separately below.

> using inflation rates effectively sets aside all the effort that was used to develop a robustly supported Five-Year Distribution Plan. When the Commission ordered the Company to create a Five-Year Plan, it did so because it understood that a thoughtful effort that considered multiple factors was needed. Using inflation rates does not consider the investments that are needed to address aging infrastructure, system risks and the need to bring new technology to support improved grid operations. [4T 851]

The Commission required DTE Electric to create a Five-Year Plan to address aging infrastructure, system risks and the need to implement new technology. Staff instead asks DTE Electric to ignore that Five-Year Plan, without identifying any disagreements with the elements of the plan itself, and merely maintain the status quo. The Commission should not adopt the PFD/Staff's proposed disallowance, as it arbitrarily reduces the funding needed to execute the Five-Year Plan without rejecting or otherwise disagreeing with any part of the Five-Year Plan.

Finally, Staff initially used, and continued to use, an arbitrary and unreasonable approach to test whether its projection of Strategic Capital is reasonable and prudent (4T 850, 852-53). Staff reasoned that the Company was "on track" for 63.7% spending in 2018, and that a reasonable "middle ground" (between 63.7% and 100%) would be 81.9%, so Staff's projections are reasonable because they are greater than 63.7% (Staff Initial Brief, p 44-45). Again, this type of reasoning is not based not upon facts and system needs. Mr. Bruzzano explained that Staff's starting point (then 61.3% based on spending as of August 2018) was not appropriate. Strategic Capital spending was impacted by several adverse weather effects in 2018 and is not indicative of the pace at which the Company will spend Strategic Capital going forward in 2019 and 2020 (4T 38). Staff's approach of taking the "middle ground" (between partial-year 2018 spending and 100% of 2019 projected spending) is also unsupported and arbitrary. The Company is ramping up resources to expend 100% of its planned capital. While there are risks to the ability to always achieve this, the Company has been pursuing several initiatives to ensure that sufficient resources

are in place to execute all planned investments (4T 796-800). Therefore, there is no sound basis for the Commission to set the Company's capital expenditures based on Staff's "middle ground" calculation (4T 852-53).

DTE Electric maintains that the proposed disallowances should be rejected completely, for the reasons discussed above.[12]

3. DTE Electric appropriately based its projected DO Capital Expenditures upon its Five-Year Plan.

The PFD recognizes that the Five-Year Plan has value, but suggests that the value relates only to providing visibility into system needs, and not necessarily to justify spending (PFD, pp 65-66). But that visibility into system needs provides a snapshot of the condition of the Company's electric system, including a high number of assets reaching or exceeding expected useful life, and clearly shows that maintaining the status quo will not meet either the Company's or the Commission's reliability goals. The Company maintains that if its system needs repair, or improvement, then spending is justified to satisfy that need.

The Company further disagrees with the PFD's distinction between system needs and spending because the Five-Year Plan was prepared as directed by the Commission to address the highest-priority risk and reliability issues faced by the Company's customers. The next version of the Five-Year Plan will similarly prioritize highest-priority risk, and the categories where spend is required are not likely to be significantly different from the current Five-Year Plan. Delaying the implementation of the investments described in the Five-Year Plan would jeopardize DTE Electric's and the Commission's goal of achieving better safety, reliability and resiliency for the

[12] For completeness, DTE Electric notes that the PFD rejected the AG's proposed disallowance for Infrastructure Resilience and Hardening/Redesign and the Staff's proposed disallowance for the Company's 3G to 4G upgrade as duplicative of the Staff's proposed disallowances (PFD, pp 79, 85). The Company agrees that these proposed disallowances should be rejected, adding that to the extent that the Commission reaches the merits of these proposed disallowances, they should be rejected as discussed in DTE Electric's Reply Brief, pp 37-39, 46-47).

Company's customers. It would not be in the best interest of the Company's customers to delay the implementation of the Five-Year Distribution Plan for hypothetical outcomes from other cases or regulatory proceedings. Moreover, the November 21, 2018 Order in Case No. U-20147 recently clarified, at page 36, that the purpose of the next round of distribution plans will not be appreciably different than current, or carry significant new requirements on utilities:

> [T]he purpose of the framework for the next round of distribution plans is to provide focused discussion, longer-term visibility than what is available in a rate case, and better understanding, not to set prescriptive mandates on utilities . . . The Commission cannot usurp utility management prerogatives. *See*, *Union Carbide Corp v Pub Serv Comm*, 431 Mich 135, 148; 428 NW2d 322 (1988). Thus, any framework at this time is not to be treated as a one-size-fits-all approach but is to be used as a guide for the next iterations of distribution plans to be filed by those directed to do so. [Nov. 21, 2018 U-20147 Order at p.36]

DTE Electric's next Five-Year Plan is due by June 30, 2020 (*Id*). Thus, the present Five-Year Plan and the Company's testimony and supporting exhibits fully and appropriately support all planned distribution investments in this case. Changes in the format of future Five-Year Plans will not reduce the age or improve the condition of the Company's distribution assets rendering planned investments unnecessary, as intervenors have suggested (4T 874-76, 883-86).

4. There is no need to revise rate case filing requirements.

In the context of approving historical expenditures, the PFD raised a concern about the Staff and intervenors having to create a "crosswalk" between spending categories from the Company's previous rate case, and suggested that the Commission should consider revising rate case filing requirements for utilities to explain how spending classifications in a previous case translate into the current case (PFD, p 67, 93-94). The Company appreciates the PFD's concern,

and will endeavor to address these issues on a going-forward basis. Since the Company will do this voluntarily, the PFD's suggestion to revise rate case filing requirements appears to be moot.[13]

C. The Company's Demand Side Management ("DSM") programs are reasonable and prudent and should be approved.

DTE Electric supported capital expenditures for Demand Side Management ("DSM") programs consisting of Interruptible Air Conditioning ("IAC"), DTE Energy Insight, Programmable Communicating Thermostats ("PCT"), and Other DSM Programs (3T 354; Exhibit A-12, Schedule B-5.6). The Company proposes investment of $6.2 million (for January 2018 through April 2019) to complete the enrollment of the initial 10,000 customer level approved in Case No. U-18014, and an additional $3.4 million for the projected test year for the enrollment of an additional 7,000 customers by summer of 2020.

The Commission previously agreed with Staff's proposal to limit DTE Electric to 10,000 PCTs in Case U-18014, noting that "[i]f DTE Electric demonstrates that its DR programs are successful in the initial phases, additional DR expenditures will be recoverable in a subsequent rate case" (January 31, 2017 Order in Case No. U-18014, p 25). In the Company's last general rate case, the Commission agreed with the PFD's recommendation to disallow the Company's request for $6,133,000 to purchase 25,000 PCTs, stating that the "Commission agrees with the utility that complete installation was not necessary to support increased funding, but a showing of initial success was" (April 18, 2018 Order in Case No. U-18255, p 22).

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[13] An issue is moot when an event occurs that renders it impossible for the decision maker, if it should decide in favor of the complainant, to grant any relief. *Swinehart v Secretary of State*, 27 Mich App 318, 320; 183 NW23d 397 (1970). Courts generally dismiss cases presenting only abstract questions that do not rest on existing facts or rights. *B P 7 v Bureau of State Lottery*, 231 Mich App 356, 359; 586 NW2d 117 (1998) (dismissing appeals because issue presented became moot). See also, *International Union v Michigan*, 211 Mich App 20, 29; 535 NW2d 210 (1995) (dismissing claims that had been rendered moot by subsequent developments); *Plumbers and Pipefitters Local Union No 190 v Wolff*, 141 Mich App 815, 818; 369 NW2d 239 (1985) (declining to address moot issues).

The Company proposes investment of $6.2 million (for January 2018 through April 2019) to complete the enrollment of the initial 10,000 customer level approved in Case No. U-18014. The Company further proposes an additional $3.4 million for the projected test year for the enrollment of an additional 7,000 customers by summer of 2020. (Exhibit S-21).

Staff indicated general support for the Company's DR efforts, but recommended a $9.6 million disallowance for the proposed PCT program ($6.2 million for the 16-month bridge period; $3.4 million for the projected test year) based on the contention that the Company has not demonstrated that the program has been successful enough in the early stages to merit the funding of additional PCT units beyond the 10,000 units that the Commission approved in Case No. U-18014 (Staff Initial Brief, pp 17-12). The PFD agreed (PFD, p 92).

DTE Electric believes there is confusion with respect to the funding level included in this case associated with the already approved 10,000 PCT program, and funding levels associated with incremental new investment in PCT's. The $6.2 million request in this case is intended to complete the enrollment of the initial 10,000 customer level already approved in Case U-18014 (Exhibit S-21). Additionally, as shown on Exhibit S-21, the $6.1 million in capital is associated in large part with an investment in the Company's Distributed Energy Resource Management System, which is necessary to run the PCT program whether there are 10,000 or 100,000 customers enrolled. To deny these costs would essentially deny the Company the ability to run the PCT program. DTE Electric maintains that its requested funding is justified by the progress and success in implementing the initial phases of the PCT program. The Company has purchased equipment and engaged in marketing and outreach efforts to enroll customers. The PCT program successful in the four events that the Company called during the summer of 2018, with a meaningful decline

in electricity usage in the critical hours of the events (an average of 1.05 kW per participating customer). (3T 385)

The Company had enrolled approximately 3,900 customers as of November 12, 2018, which is in line with the revised forecast to enroll 4,500 customers by December 31, 2018 and the Company's continuing commitment to achieving 17,000 by the summer of 2020 (3T 386-87). Enrollment is forecasted to be complete for the initial 10,000 customers by the summer of 2019. The associated projected investment to fulfill the initial 10,000-customer enrollment goal includes the historical expenditures as of December 31, 2017 ($2.1 million) plus the projected expenditures during the bridge period ending April 30, 2019 of $6.2 million (See Exhibit S-21). Thus, current enrollments support a finding of success in the program's initial stages.

It is also important to keep in mind that the Company's efforts to date have been significantly focused on launching and developing the program. Lessons learned from initial marketing efforts are being incorporated in new campaigns to increase enrollment and event participation. Therefore, the PFD/Staff's proposed $9.6 million disallowance should be rejected and the PCT program should be fully funded as the Company requests (3T 386-87) to build on the initial success of the program. In the alternative, the Commission should at least approve $6.2 million to complete the initial 10,000 customer enrollment which was approved in U-18014 as discussed above.

The PFD also discusses performance goals, but DTE Electric is unclear in the intent of the discussion. The PFD states:

> With respect to the Staff's recommended performance goals for DSM, this PFD agrees that such goals should be established as part of DTE Electric's overall demand response plan, subject to refinement over time through the IRP process. For the purposes of this case, the Staff's recommended performance goals (expected spending, MW reduction) should be adopted. [PFD, p 92.]

DTE Electric maintains that any performance goals for DR programs should be established and implemented as discussed by Ms. Dimity (3T 388-89) and disagrees to the extent that the PFD suggests otherwise.

D. The Company's information technology capital expenditures are necessary to support utility operations and customer service and should be approved.

DTE Electric supported capital expenditures for the Information Technology ("IT") Organization (5T 1350; Exhibit A-12, Schedule B5.7). Staff proposed a $13,619,000 disallowance ($3.889 million in the bridge period and $9.730 million in the test year) for several IT programs (Staff Initial Brief, pp 20-25). The PFD rejected the Staff's proposed disallowance for the ConnectUs Phase 4 project (PFD, p 93), but recommended adopting Staff's additional proposals (*Id*, pp 95, 97-98). DTE Electric maintains that its requested recovery should be fully approved because it is required for prudent and necessary projects to support utility operations and customer service (5T 1398).

Staff recommended that the Customer Digital Channels (MSA) Sustainment project be completely disallowed because it is based on historical needs (Staff Initial Brief, p 22). Mr. Griffin explained that this project is based on an existing backlog of kiosk, web, mobile, and IVR enhancements that are prioritized on an ongoing basis throughout the bridge and test periods. This list is constantly updated based upon the customer team's analysis of items on the list and anything that emerges either from customers or from interaction with Staff. This allows the Company to react to changes in either the consumer experience or to the requests developed by the Commission or other customer advocates (5T 1408-1409).[14] Despite this record evidence, the PFD states:

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[14] Mr. Griffin further stated in Staff Exhibit S-12.2, page 9 in response to CSM 5.10a, that the scope includes the following over the next 12-18 months, including a priority focus on improvements, examples of which include:
- Response time enhancements
- Kiosk payment improvements

> This PFD agrees with the Staff that its proposed disallowance, totaling $3,195,000 is reasonable. As the Staff contends, given the rapid advances in technology, historical spending is not necessarily a true indicator of projected spending. In addition, if the spending in this category represents a backlog, the company should be able to provide more detail on what it expects to accomplish in the bridge and test years. [PFD, p 95.]

Historical spending reflects the amount of money that will be spent, but it will not necessarily be spent on the historical backlog "given the rapid advances in technology" that the PFD/Staff acknowledge. Actual spending is prioritized and constantly updated, as discussed above and further explained below.

Staff also proposed a full disallowance for the IT Business Planning and Development project and partial disallowances for the 2018 Emergent and coDE Sustainment projects, reasoning that the projects are uncertain (Staff Initial Brief, pp 24-25). The PFD stated that it "agrees with the Staff that, in light of the uncertainty about the need for the projects, coupled with the unknown cost of emergent items, the Staff's recommended disallowances are reasonable and should be adopted" (PFD, p 98). The Company disagrees. Mr. Griffin explained in part that the projects are known, it is merely the final scope of the projects that are not yet finalized:

> In Exhibit A-38, Schedule BB-1, pages 1 and 2, the Company indicated that the ITS Annual Planning Cycle (APC) is the process by which the Company prioritizes, approves and undertakes IT related Projects . . . [detailed discussion of process omitted]. Each portfolio finalizes its investment list for the next year during the last quarter of the current year and updates its roadmaps based on those committed projects and enhancements. Because of this, it is inaccurate to assert that the Company does not have known and planned work for this recovery. A better representation would be that the investments that will be included are known and

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- Outage trouble reporting
- Improve Move in Move out process on web
- IVR outage reporting enhancements
- Enhancements to Agency website for supporting low income customers
- Managing Customer Profile Information/Functionality (4T 1409).

> that it is only the actual final scope that is not solidified earlier in the planning process. [5T 1402.]

Mr. Griffin explained that the IT Business Planning and Development Sustainment project, like other customer portfolio projects of this type, has a backlog of requested upgrades and feature enhancements that the Company prioritizes on an ongoing basis throughout both the bridge and test periods. This list is constantly updated – sometimes due to interactions with Staff. It is inaccurate to characterize this flexibility as uncertainty when updated prioritization instead allocates resources to help ensure that customers' needs are met in a timely manner (5T 1403). History has also shown that certain types of investments arise every year and are necessary to keep the Company running efficiently, so the amount of spend on these items can be forecast in the aggregate (5T 1403-1404).[15]

In response to Staff's apparent misunderstanding, Mr. Griffin explained the 2018 Emergent project, which allows the Company to take advantage of technology advancements and trends during the bridge and test periods. The Innovations Project Management Office ("iPMO") has been formed to govern the emergent initiatives, experiments and projects represented within this project. The investments resulting from this project constitute prioritized work on a variety of programs that are known, sequenced and approved for investment (5T 1404-1405). Mr. Griffin also explained the following technology trends that are in the pipeline and included in 2018 Emergent: Robotic Process Automation; Drones; Industrial Internet of Things; Augmented Reality; and Artificial Intelligence and Machine Learning. (5T 1405-1407; Exhibit A-38, Schedule BB-2).

[15] Typical Sustainment work regularly includes the addition of disk storage to account for growth, additional hardware for memory and performance enhancement, and end-of-life replacements (5T 1404).

The coDE Sustainment project presents another unique scenario, this time involving DTE's only in-house custom IT development staff, which operates from a prioritized backlog of requested upgrades and feature enhancements reviewed on an ongoing basis (again, sometimes due to interaction with Staff) throughout both the bridge and test periods. Like the previous categories, these investments are not uncertain. Instead, the Company is working from a *known backlog* where the only unknown is exactly which of the programs will be prioritized the highest based on ongoing input from customers and the Commission or its Staff (5T 1407-1408).

Staff also grouped the Work Management Sustainment (Maximo/ESri/Service Suite), Fuel Supply Sustainment, GenOps Business Sustain, IT FosGen Business Sustain, and Fermi – Nuclear Gen Sustain projects together, and generically proposed a partial disallowance based on the assertion that the Company-provided audit responses include a total expected cost that falls below the amount originally indicated, so a disallowance should be made for the suggested surplus in each project (Staff Initial Brief, pp 23-24). The PFD agreed stating:

> This PFD finds, that as has occurred in past DTE Electric rate cases, the company has included "placeholder" amounts for these items identified by Staff, with the intention of finalizing its spending plan at some point in the future. If the only information DTE Electric has available at the time it files its case is a draft plan, to which it apparently adds a financial "cushion," then it is reasonable for the Staff or other parties to the proceeding to base their respective projections on the company's draft and responses to discovery. [PFD, p 97].

Mr Griffin's testimony discusses a representative set of investments rather than detailed breakdown for each project. For example, regarding the specific topic of Sustainment efforts in Plant & Field, Mr Griffin discussed the "most significant" investments being made in the space (5T 1370). Mr. Griffin also spoke to these same investment samples, explaining their significance as "targeted at prudent system investments designed to ensure that our existing systems are upgraded to comprehend both increased load and to handle expanded demand." (5T 1373, 1374)

However, these were not presented as the only investments included in the requested allowances for the Plant and Field space.

Similarly during the audit and discovery phase, the Company provided Staff with year-to-date spend in these investments, and answered discovery from the AG. Again, at no point in this case did the Company suggest that these were the only investments in the Plant & Field space, nor was any discovery received requesting an exhaustive list of all investments. Moreover, the extensive long term planning included in the DTE Electric process was explained as an "in-depth and ongoing analysis of continually evolving backlogs of work driven by customer experience, enhancement requests, and maturing business needs," producing backlogs which are, "substantial and align to many years' worth of investment," and which, "results in a body of work that routinely exceeds a single calendar year of effort, which is used as input into the APC cycle" (5T 1410). The investments offered as examples and characterized as significant were the investments that were queued at the top of the backlog list.

The PFD's recommended disallowance appears to be predicated on the assertion that the initial work discussed presented by the Company represents the totality of the activity in the particular business cases. However, Mr. Griffin explained that "[i]t would not be practical for the Company to produce, or the Staff to have to review, thousands of pages of documentation regarding each enhancement that makes up the backlog especially since none of the portfolio's backlogs will be completely exhausted in a single rate case period." (5T 1410-1411).

Mr. Griffin also explained Annual Planning Cycle process to prioritize known work into achievable years as well as the rigor in adopting and establishing this methodology. Specifically, Mr. Griffin testified that "the investments that will be included are known and that it is only the actual final scope that is not solidified earlier in the planning process. Because of this early

submission of the portfolio's business cases can leave one with the impression that this is simply contingency when in fact it is not." (5T 1402). The Company received no further indication from the parties that this explanation was insufficient.

The costs identified by Mr. Griffin are known, and as stated above and in Mr. Griffin's testimony, the only unknown is how the projects will be prioritized. It bears emphasis that as indicated above, DTE Electric's process for any Sustainment case is an in-depth and ongoing analysis of continually-evolving backlogs of work driven by customer experience, enhancement requests, and maturing business needs. [16] These backlogs are substantial and align to many years' worth of investment. The Company applies the methodology of the APC cycle specifically to prioritize and form an annual scope of work corresponding to the technology investment plans and roadmaps maintained for a multi-year period. This results in a body of work that routinely exceeds a single calendar year of effort, which is used as input into the APC cycle. It would also not be practical for the Company to produce, and for Staff to review, thousands of pages of documentation regarding each enhancement that makes up the Sustainment backlog, especially since none of the

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[16] Mr. Griffin explained that Staff did not consider the information provided by the Company in Exhibit A-38, Schedule BB-1 pages 1 and 2, which are responses to audit requests CSM-1.2 and CSM-5.1 (5T 1410-11).

In CSM-1.2, Mr. Griffin explained the ongoing annual planning cycle with the following statements: In general, business cases for 2019 and 2020 are in progress in accordance with the Company's Annual Planning Cycle (APC). Based on where in that process the Company is, most 2019 and 2020 business cases have not been finalized and will continue to be worked through the scheduled completion of the APC. The APC is undertaken each year to align the capital projects with the planning roadmaps and to ensure that projects are prioritized and sequenced correctly. As part of the Part III Filing Requirement, the Company did provide draft business cases for anything that was in the top 25 project list as requested.

CSM 5.1 later raised the question: "When will the 2019 and 2020 business cases be finalized? When is the scheduled completion of the APC?" Mr. Griffin responded explaining that 2019 Business Cases will be finalized mid-fourth quarter. Initial planning for 2020 Business Cases has begun and the cycle for 2020 will finalize in the fourth quarter of 2019. (5T 1410).

portfolio's backlogs will be completely exhausted in a single rate case period. Therefore, the PFD/Staff's proposed disallowance should be rejected (5T 1411-12).

E. The PFD's proposed IT reporting requirements should be refined.

Staff also made recommendations regarding documentation that should be provided in future rate cases (8T 4151-53). Mr. Griffin agreed in part, noting that Staff recommended several viable points that, in the interest of clarity, the Company would be willing to consider with some modifications regarding timing, volume, complexity/effort to comply, and spend thresholds (5T 1412). Mr. Griffin discussed each of Staff's suggestions in detail, along with counter-suggestion to address the Company's concerns (5T 1413-17). Staff largely agreed with the Company, stating that "the ALJ and Commission should adopt Staffs [sic] recommended filing suggestions with DTE's modification for all but Staff's final recommendation," which is "that the Company breakdown any IT programs that were approved in its previous rate case that were not completed or were 20% above or below the approved project amount and include an explanation of why the project was not completed or why it was off budget" (Staff Initial Brief, p 26). The PFD agreed (PFD, p 101).

The Company disagrees on the significantly-narrowed, but important issue that remains. Mr. Griffin explained that unless the Staff's final recommendation is tempered by a threshold of projects above $500,000 and limited to those projects for which the Company is seeking additional funding, the administrative burden of the request would be excessive and unworkable (5T 1417.)

The Company is also concerned that the PFD/Staff's suggestion to adopt a filing requirement for past expenditures in a case not seeking additional recovery would invite an improper exercise in hindsight (5T 1417). As Mr. Stanczak testified, the projected test year is a projection of the expenditures that are likely to be made given the information known at the time of

the rate case filing. There is no legal basis to use hindsight to reconcile the difference between projected expenditures from a prior rate case against actual expenditures incurred in a historical period.[17] In a rate case proceeding, the Commission authorizes the Company's rates based on a revenue requirement including a reasonable rate of return, but it does not set fixed spending levels (3T 97; 4T 825). There is no provision in any applicable statute that calls for a reconciliation of established rates and the Commission lacks authority to order such a procedure. *Consumers Power Co v Public Service Comm*, 460 Mich 148; 596 NW2d 126 (1999); *Union Carbide v Public Service Comm*, 431 Mich 135, 148-49; 428 NW2d 322 (1988), *see generally* MCL 460.6a. This is why the Company proposes to limit the requirement to those projects for which the Company is seeking additional funding. Only in such a case is the progress and costs on a project relevant to determining the revenue requirement.

F. The PFD's proposed disallowance for Corporate Staff Group capital expenditures should be rejected.

The PFD recommends that the Attorney General's proposed reduction of $17,052,000 to capital expense for the corporate staff group ("CSG") should be adopted on the basis that the Company did not provide rebuttal testimony to Witness Coppola's recommendation. As cited in the PFD, Mr. Coppola testified:

> The $17.1 million is a significant variance from the forecasted level and this under-spending trend is likely to continue into the remaining months of 2018. However, giving the Company the benefit of the doubt that capital expenditures in the remaining four months will meet the forecasted level, it is reasonable to conclude that the cumulative under-spent amount of for the 8 months ended August 2018 is

[17] The Commission has no common law powers, but only possesses the limited authority that the Legislature conferred upon it. *Consumers Power Co v Public Service Comm,* 460 Mich 148, 155; 596 NW2d 126 (1999). The Commission is an "administrative body created by statute and the warrant for the exercise of all its power and authority must be found in statutory enactments." *Union Carbide v Public Service Comm,* 431 Mich 135, 146; 428 NW2d 322 (1988); *Sparta Foundry Co v Public Utilities Comm,* 275 Mich 562, 564; 267 NW 736 (1936). The Commission's authority must be conferred by clear and unmistakable statutory language, and a doubtful power does not exist. *Mason Co Civil Research Council v Mason Co,* 343 Mich 313, 326-27; 72 NW2d 292 (1955).

likely to remain. Therefore, I recommend that this amount be removed from the projected capital expenditures and from rate base.

The PFD agreed on the sole basis that the Company did not appear to rebut Mr. Coppola's recommendation. The Company disagrees that this is a valid basis for accepting Mr. Coppola's recommendation. Mr. Coppola's testimony is simply an unsupported opinion. Ms. Uzenski, on the other hand, provided pages of testimony and exhibits to support the capital spending for the CSG group, identifying particular projects and the cost of those projects (7T 3314 – 3321, Exhibit A-12, Schedule B5.8). The weight of the evidence supports a finding that DTE Electric's spending in this area is reasonable and prudent. Mr. Coppola's speculation that the Company will not likely spend what it forecasts, does not outweigh, nor is it more persuasive than, the substantial evidence provided by the Company. As such, the PFD's recommended disallowance should be rejected.

IV. RATE OF RETURN

A. DTE Electric should have a weighted after-tax rate of return of 5.72%.

The PFD recommends a weighted, after-tax overall rate of return of 5.48% (PFD, p 130, 301). DTE Electric supports the PFD's cost factors of 4.36% for long-term and 3.56% for short-term debt (PFD, p 123 and Appendix D), [18] but takes exception regarding the PFD's recommended capital structure (PFD, pp 114-16), and return on equity ("ROE") (PFD, pp 128, 301).

[18] PFD, p 123 indicates an uncontested short-term debt rate of 2.77%, which apparently is just a typo, since Appendix D reflects 3.56%. DTE Electric's Initial Brief, p 50, summarized the Company's recommendation for a 3.56% cost of short-term debt, which includes the interest rate on short-term borrowings and facility fees associated with the credit arrangements necessary for the issuance of short-term debt. Staff (Initial Brief, p 50) and the AG (Initial Brief, p 92) agreed. Therefore, the ALJ apparently meant to recommend, and the Commission should adopt, a short-term debt rate of 3.56%.

1. The Company's proposed capital structure would allow it to maintain adequate access to capital at the lowest reasonable cost and should be approved.

DTE Electric needs to increase its permanent capital structure to approximately 49% debt and 51% equity, which is stronger than the 50/50 capital structure that the Commission approved in the Company's last general rate case (April 18, 2018 Order in Case No. U-18255, p 25) (5T 1037-38, 1057; Exhibit A-14, Schedule D1). Staff agreed (Staff Initial Brief, p 49). The PFD disagreed, stating: "The PFD agrees with the Attorney General and ABATE that DTE Electric failed to provide sufficient evidence that its capital structure should be adjusted at this time to compensate for the purported impacts of the TCJA and the company's capital spending program" (PFD, p 114).

The record demonstrates that it is important to strengthen the Company's capital structure to 51% equity to enhance the Company's credit quality and financial soundness. Capital structure is critical because it determines a company's access to credit markets (the *availability* of capital), and ability to raise capital at reasonable terms and rates (the *cost* of capital). If DTE Electric is unable to raise adequate capital, then the Company will be unable to invest in the equipment and systems necessary to ensure efficient, reliable and safe electric service for its customers (5T 1038-47, 1057).

The Commission previously maintained DTE Electric's 50/50 structure, reasoning that "conditions have not changed to such a degree as to warrant a departure from a balanced equity ratio at this time" (April 18, 2018 Order in Case No. U-18255, p 25). Mr. Solomon testified that it is now reasonable and prudent to increase the equity ratio to 51%, explaining in part:

> The capital structure recommendation increases the financial soundness and creditworthiness of the Company at a time when it is facing the material, negative impacts of the Tax Cuts and Jobs Act of 2017 ("TCJA" or "tax reform"). The requested equity ratio of 51% is below the peer average, and even lower than peers when considering the significant adjustments the ratings agencies make to the

> Company's debt calculations. The increased equity level is especially important given the significant capital investments the Company is making over the next 5 years to maintain and improve the electric infrastructure to benefit our customers. [5T 1041. See also 5T 1042-47.]

More specifically, the TCJA has significant negative impacts on a utility's cash flow and, in turn, its credit metrics. Essentially, the lower tax rate and the loss of bonus depreciation causes utilities to lose some of their cash flow contribution from deferred taxes. This decreases the Funds From Operations ("FFO") to debt ratio, which is a key metric that credit rating agencies use to measure credit quality. Regulators in other states have acknowledged the negative impacts of tax reform on utilities and are allowing relief including increased equity ratios (5T 1041-45, 1063). The TCJA also results in a re-measurement of deferred taxes due to the reduction in the tax rate, so the Company proposes to credit these excess accumulated deferred income tax ("ADIT") balances back to customers beginning with this case (see generally, section VII. F of DTE Electric's Initial Brief regarding Income Tax Expense).

DTE Electric will be financing and funding $4.0 billion of electric capital expenditures for the period of January 2018 through April 2020 (Exhibit A-12, Schedule B5). [19] A capital structure with 51% equity will enhance DTE Electric's credit quality and financial soundness, which will in turn ensure the reasonableness and competitiveness of the Company's capital costs during this period of significant system investment (5T 1047).

AG witness Mr. Coppola suggested that Mr. Solomon was misleading in attributing Moody's placement of DTE Gas on negative outlook primarily due to tax reform because Moody's actions were also due to DTE Gas's near-record-high level of capital expenditures (5T 1659). Mr.

[19] Moreover, as discussed in part above, DTE Electric has capital needs to address its aging infrastructure to ensure reliability and safety (See also DTE Electric Reply Brief, sections V. A. and C).

Solomon disagreed and noted that DTE Electric and DTE Gas both have near-record-high levels of capital expenditures:

> Moody's would not have placed DTE Gas on negative outlook if tax reform had not occurred. The tax reform change prompted Moody's to downgrade its outlook on the entire utility industry and in May 2018, downgrade the outlook on DTE Gas. Moody's did reference that DTE Gas's capital expenditures are near record highs. Similarly, DTE Electric's capital expenditures are near record highs. The Company is making significant capital investments over the next five years to maintain and improve our infrastructure that directly benefit our customers. These capital expenditures are necessary to provide service to our customers. A common equity ratio of 51% is reasonable given the negative impact of tax reform on credit metrics especially during a time of increased capital expenditures. [5T 1063.]

DTE Electric's proposed 51% equity ratio is lower than the 52.8% average for the Company's peer group (Exhibit A-14, Schedule D1.1). After rating agency adjustments to debt, the average equity ratio for the peer group is 47.8%, compared to 44.6% for DTE Electric (Exhibit A-14, Schedule D1.2). Thus, on an adjusted basis, the Company's equity ratio is 3.2% lower than its peers (5T 1046-47). In other recent peer utility rate cases, the MPSC has authorized a 52% or higher equity ratio for all utilities except DTE Electric. DTE Electric's proposed 51% is the lowest requested ratio among those cases (5T 1045-46).

The AG opposed DTE Electric's proposed capital structure for three reasons (AG Initial Brief, p 85-86). The first is Mr. Coppola's assertion that "the common equity ratio of the peer group used to assess the cost of common equity in this case, averages 47.6%" (AG Initial Brief, p 85). Mr. Solomon explained that Mr. Coppola's referenced peer group was not a valid comparison as it used holding company data. DTE Electric is not a holding company and should be compared to other electric utilities, not holding companies. The average common equity as of June 30, 2018, for the electric company subsidiaries of the holding companies that Mr. Coppola selected as his

peer group was 51.6%, which is comparable to DTE Electric's 51% request in this case (5T 1061; Exhibit A-35, Schedule Y-1).[20]

The AG's second reason for opposing DTE Electric's capital structure is Mr. Coppola's suggestion that it that it would be reasonable for DTE Electric to have the same capital structure as Consumers Energy ("Consumers") and that the Commission directed Consumers to move toward a 50/50 capital structure in Case No. U-17990 (AG Initial Brief, p 86). Mr. Solomon agreed that DTE Electric and Consumers are similar, and it is reasonable for them to have similar capital structures; however, Mr. Coppola neglected that the Commission authorized a capital structure with 52.87% equity in Case No. U-17990, and recently authorized a capital structure with 52.64% equity in Consumers' subsequent rate case (March 29, 2018 Order in Case No. U-18322, p 35). In then-pending Case No. U-20134, Consumers requested a capital structure with 52.5% common equity, and also noted that the path to 50% equity is no longer reasonable due to the TCJA. Thus, DTE Electric's request for a 51% equity ratio is reasonable and comparable to its peers (5T 1062).[21]

The AG's third reason is the unsupported assertion that "DTE Energy can make the Company's common equity ratio of its subsidiaries whatever it wants" (AG Initial Brief, p 86). The AG neglected that the Commission must base its decision on the record, which reflects that DTE Electric also had a 51% equity ratio on December 31, 2017 and is committed to maintaining

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[20] Mr. Coppola also took DTE Energy's common equity percentage strictly from 10Q data, which is inaccurate because it fails to consider that DTE Energy's junior subordinated debt and mandatory convertible debt effectively increase the equity in its capital structure (5T 1061-62).

[21] The AG then suggested that the Commission should not consider Case No. U-20134 (AG Initial Brief, pp 89-90). To the contrary, the Commission is certainly entitled to take notice of its own January 9, 2019 Order Approving Settlement Agreement in Case No. U-20134, and that the AG did not object to that settlement agreement, which apparently did not alter Consumers' capital structure.

a 51% equity ratio. DTE Energy has made substantial equity infusions in the past, and plans equity infusions of $372.2 million in 2018, $200 million in 2019, and $200 million in early 2020, which will result in a 51% equity ratio for the projected test period (5T 1047-48).

The PFD was unpersuaded by DTE Electric's evidence regarding impacts on its credit ratings, but instead opined: "While DTE Electric cites a number of factors that might have some effect on the company's credit ratings, the ALJ notes that as of the close of the record in this case, the TCJA has been in effect for almost a year, with no discernable impact on the Company or its strong credit ratings' (PFD, p 115. Emphasis in original). The record plainly demonstrates that there is recent, negative pressure on DTE Electric's financial metrics, and therefore its credit rating, at the same time that DTE Electric is financing and funding substantial capital expenditures. DTE Electric does not agree that the ALJ should see a discernable negative impact on the Company or its credit ratings before supporting a stronger balance sheet. DTE Electric has maintained its capital structure at 51% equity during the time the negative impacts of the TCJA have occurred and this increased equity level helps protect against negative credit impacts. The proper time to take corrective action is before a predictable problem occurs, not after it is too late.

The PFD also cited ABATE's argument that the Company's plans to increase its dividend by 2020 is not meant to financial stabilize the Company, but to provide a payout ratio of 136.4%.[22] However, the 136.4% payout ratio calculated by ABATE only occurs in the event there is no rate relief. In ABATE Witness Walters' Table 5 (7 T 2971), the 136.4% he presents is calculated using a net income of $401 million, a decrease from 2018 of $241 million. The $401 million net income is also based on a calendar year rather than the projected test year and assumes no rate relief. These

[22] The dividend payment amount reflected on page 114 of the PFD is $886.7 million; however, the correct amount is $86.7 million.

assumptions, severely impact the resulting dividend payout ratio. The 75% payout ratio with rate relief shown on Mr. Solomon's Exhibit A-11 Schedule A2, line 50 is accurate, reasonable and consistent with historic payouts as Mr. Gorman recognizes in his Table 5 (73% for 2018).

In support of its recommendation, the PFD also cites Mr. Coppola's testimony that a possible 24 basis point increase in interest rates would be insignificant compared to the increase in equity ratio requested. The Company typically issues debt with a 30-year term, therefore, the 24-basis point increase would impact customers over 30 years. It would also impact all subsequent debt issuances of the Company and in a period of significant capital expenditures the need for long-term financing will also be significant.

Also of note, while the PFD rejected ABATE's proposed "regulatory plan" involving the faster amortization of unprotected excess ADIT balances, the ALJ also recommended that this option be studied further in the Company's next rate case. DTE Electric disagrees that there is any need to study this proposal further given the negative impact to Company's cash flows as explained by Mr. Solomon (See 6 T 1064-1065). Furthermore, ABATE's regulatory plan proposal was based on an assumption that the Company's new depreciation rates would be higher due to the retirement of its Tier 2 plants. In the approved settlement agreement in Case No. U-18150, the Company was directed to maintain the existing depreciation rates from the U-16117 Order for its Tier 2 plants. As a result there is no increased depreciation expense, thus making the proposed analysis unnecessary.

In summary, DTE Electric needs a strong equity component of its capital structure to maintain adequate access to capital at the lowest reasonable cost during a period of significant capital investment. DTE Electric is also facing the material, negative impacts of the TCJA, which could lead to a credit rating downgrade that would reduce access to capital and could negatively

impact credit spreads, increasing the cost of debt and adding to customer costs (5T 1048). DTE Electric also continues to balance capital investment plans, credit metrics and customer rate impacts, while it continues to face significant ongoing and emerging business challenges, as further discussed below (see also section VI. C. 3 of DTE Electric's Initial Brief). Accordingly, the Commission should strengthen DTE Electric's equity ratio from 50% to 51%.

2. The Company's proposed return on common equity is reasonable and necessary given the economic and financial environments.

The PFD recommended maintaining the 10.0% return on equity ("ROE") for DTE Electric's common equity capital (PFD, pp 128, 301). The Commission should instead adopt Dr. Vilbert's recommendation that a just and reasonable ROE for DTE Electric's common equity capital is 10.5%. This is at the upper end of Dr. Vilbert's range of 9.75% to 10.75% because DTE Electric has greater-than-average risk (6T 1919, 1975-76, 2016). The uncertainty in the capital markets, the more challenging Michigan economic environment, the differences in financial risk for DTE Electric as compared to sample companies,[23] and the large-scale disruptive changes in the utility industry justifies an increase in the recommended ROE for DTE Electric relative to the sample companies (6T 1918-20, 1923-37, 1975-77, 2069-70).

Staff recommended 9.80% (Staff Initial Brief, p 51). The AG recommended 9.5% (AG Initial Brief, p 92). ABATE recommended 9.3% (ABATE Initial Brief, p 26).[24] The PFD rejected

[23] Dr. Vilbert selected a sample of 25 regulated electric utility companies in the same line of business as DTE Electric (6T 1916, 1937). Also, based on Case No. U-18014, Dr. Vilbert presented a subsample of 6 electric utilities that excluded DTE Energy, and had net plant greater than $6 billion but less than $20 billion (6T 1938-40).

[24] Wal-Mart and RCG disagreed with DTE Electric's proposal, but did not offer any alternative (Wal-Mart Initial Brief, p 3; RCG Initial Brief, pp 8-10). MEC/NRDC/SC (Initial Brief, pp 97-104) suggested that the Commission should depart from well-established ROE requirements, which invited an unlawful result for purposes of this case. See, for example, the April 18, 2018 Order in Case No. U-18255, p 26, noting the "landmark United States Supreme Court cases" concerning the "criteria for establishing a fair return for public utilities."

these proposals to reduce DTE Electric's ROE; however, the PFD found that the usual discussion of the parties' underlying analyses was unwarranted (PFD, p 125), and further stated:

> Instead, as the Commission has noted, "it is not realistic to make a significant change in ROE absent a radical change in underlying economic conditions" [quoting March 29, 2018 Order in Case No. U-18322, p 44]. Thus, this PFD finds the determination to be made is whether "underlying economic conditions" have changed significantly since April 18, 2018, to justify DTE Electric's recommended 10.5% ROE or, conversely, to justify the 20, 25 or 65 basis point reduction in ROE recommended by Staff, the Attorney General, and ABATE, respectively.
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> * * *
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> Absent sufficient evidence to demonstrate that underlying economic conditions have changed significantly in the past year, this PFD finds that DTE Electric's ROE should remain at 10.0% as was set in the Company's last rate case. [PFD, pp 125-26, 128.]

DTE Electric notes generally that the Staff, AG, and ABATE's recommendations underestimate the effect that interest rates have had, and will continue to have, on the cost of capital for the Company. They also failed to adequately capture the risk in the electric utility industry (6T 2012-13, 2017-21, 2024-26). The recommendations are also understated due to analytical errors and the misperception that DTE Electric has average risk relative to sample companies. To the contrary, the uncertainty in the capital markets, the more challenging Michigan economic environment, and the differences in financial risk for DTE Electric as compared to sample companies justifies an increase in the recommended ROE for DTE Electric relative to the sample companies (6T 2013-16).

The PFD similarly did not appreciate the effects of changing economic conditions and increasing risk. Dr. Vilbert explained that economic conditions have improved since the financial crisis, but investor risk aversion remains elevated relative to pre-crisis periods. There is, therefore,

an increased cost of capital for all risky investments, including regulated utilities (6T 1918-20, 1923-37).

In DTE Electric's last general rate case, the Commission set DTE Electric's ROE at 10.0%, quoting Dr. Vilbert and stating that it "agrees with DTE Electric that factors such as volatility and uncertainty are currently particularly significant, and movements are more extreme in comparison to more stable historical periods" (April 18, 2018 Order in Case No. U-18255, p 32). The Commission recognized similar factors in recently setting a 10.0% ROE for Consumers Energy (March 29, 2018 Order in Case No. U-18322, p 43). In September of 2018, the Commission set DTE Gas's ROE at 10.0%, despite the ALJ/Staff's recommended lowering DTE Gas's ROE from 10.1% to 9.6%. The Commission noted some improved conditions in the approximate two years since DTE Gas's prior rate case, but stated that it "agree[d] with DTE Gas that there [was] increased volatility in the capital markets that may affect the cost of capital" (September 13, 2018 Order in Case No. U-18999, p 54).

i. Recent and continuing changes in economic conditions, increasing business risk, and the TCJA's negative effects on credit metrics justify increasing DTE Electric's ROE.

The PFD opined that except for the possible effects of the Tax Cuts and Jobs Act of 2017 ("TCJA"), all of the factors that DTE Electric highlighted in this case were present 11 months ago and recognized by the Commission in Case No. U-18255 (PFD, p 126). Dr. Vilbert testified to the contrary --volatility and uncertainty have increased since the Company's last rate case (6T 1918, 1925, 1930, 1933). Dr. Vilbert explained in part:

> There remain serious concerns of a very slow growth recovery and many factors indicate that these concerns have increased since the U-18255 proceeding. The Commission should consider the rapidly increasing U.S. Treasury bond yields and the ongoing volatility and uncertainty, as it did in the U-18255 order. All of these factors support an increase to the ROE for the Company relative to its previously allowed ROE in U-18255 (6T 1933).

In his rebuttal testimony filed on November 28, 2018, Dr. Vilbert further testified that significant uncertainty in the global markets remains, and in some ways has increased, with continuing effects on U.S. capital markets (6T 2017). He noted that his direct testimony was based on market data as of the first quarter 2018. The Fed had increased the federal funds target interest rate twice since then, which increased yields on long-term government securities. This indicates an increase in the cost of capital since the Commission issued its April 18, 2018 Order in Case No. U-18255. This trend is expected to continue.[25] Long-term utility bond yields have also significantly increased since early 2018, further indicating that the cost of capital for the utility industry is increasing (6T 2017-19).

The PFD does not appear to have considered the effects of rising interest rates, but it is undisputed that recently-set long-term and short-term interest rates of 4.42% and 1.85% (April 18, 2018 Order in Case No. U-18255, p 26) should be changed to 4.36% and 3.56% (PFD, p 123 and Appendix D). Although utility ROEs have decreased in recent years during a period of declining and low interest rates (and factoring in the unique risk and other circumstances of other utilities in other states), interest rates are rising and are expected to keep rising, and DTE Electric's ROE is being set on a forward-looking basis (6T 1924, 1977, 2018).[26]

[25] On December 19, 2018, the Fed increased the federal funds target interest rate again, and made further suggestions about the outlook for 2019, triggering a steep sell-off in stocks.

[26] Rates for utility service are set prospectively, so that the utility provides service and its customers receive service at established rates, which are based on the estimated costs of providing that service plus a reasonable return on the utility's investment. *ABATE v Public Service Comm*, 208 Mich App 248, 257-258; 527 NW2d 533 (1994). This is part of the "regulatory compact" under which the utility dedicates its private property to serve the public and correspondingly receives a reasonable return on the value of its private property. In *Board of Public Utility Comm'rs v New York Telephone Co*, 271 US 23; 46 S Ct 363; 70 L Ed 808 (1926), the United States Supreme Court explained that the just compensation safeguarded to the utility by the Fourteenth Amendment is a reasonable return on the value of the property used at the time that the property is being used for the public service. Rates that are not sufficient to yield that present return are confiscatory. 271 US at 31.

Significant business risks facing electric utilities have also increased, due for example to the transition away from coal-fired generation (6T 2020-21). ABATE witness Mr. Walters similarly acknowledged: "Transformational risks abound in the Canadian and U.S. utility sector, especially in electric utilities" (7T 2962, quoting *Standard & Poors Global Ratings*: "Industry Top Trends 2018: North America Regulated Utilities," January 25, 2018, p 1).

Moreover, the TCJA contains provisions reducing the corporate tax rate and revising the federal tax structure. Credit rating agencies have expressed concern about the financial health of regulated utilities due to the negative impact of tax reform on the companies' cash flow and credit metrics (6T 1934-37, 2021-23). [27] Dr. Vilbert explained in part:

> These effects suggest that the allowed ROE and/or the amount of equity in the capital structure should be increased to offset the negative effects of the income tax law. It is vital to maintain the financial health of the utility and the ability of that utility to raise capital on favorable terms, especially during periods of significant capital expenditures. Declining credit metrics and ratings indicate increased risk for the company, suggesting that a higher ROE would be appropriate to compensate for this risk to equity holders and/or a higher equity share in the capital structure should be allowed in order to improve the financial profile of the company [6T 1937.]

Although, as Staff pointed out, Moody's revised the outlook of 24 regulated utility companies to negative and did not include DTE Electric, credit rating agencies have all expressed concern about the TCJA's negative impact on the cash flow and credit metrics of regulated utilities, as indicated above. Dr. Vilbert explained in his rebuttal that since his direct testimony, credit rating agencies have reaffirmed their negative outlook on regulated utilities as "the negative cash flow

[27] As discussed in section VI. A of DTE Electric's Initial Brief and above, the lower tax rate and the loss of bonus depreciation causes utilities to lose some of their cash flow contribution from deferred taxes. This decreases the Funds From Operations ("FFO") to debt ratio, which is a key metric that credit rating agencies use to measure credit quality (5T 1041-43).

ramifications of the 2017 Tax Cuts & Jobs Act (TCJA) are beginning to surface in financial statements and will become more evident in the results of the second half of 2018" (6T 2024-25, quoting Moody's Investors Service, "2019 outlook negative amid growing debt and stagnant cash flows," November 8, 2018).

The TCJA has negatively affected the Company's credit metrics (including the FFO/Debt and Debt/EBITDA ratios), which were already pressured by the large capital spending plan (6T 2025). Moody's has further noted that the Company's credit metrics "will weaken going forward on account of tax reform and higher capex" and that these capital expenditures carry some lag in operating cash flow and consequently further depress an already weakened CFO profile" (Moody's Investors Service, "DTE Electric Company: Update to credit analysis," May 9, 2018). Due to these concerns, Moody's has given the Company a stable credit rating outlook "assuming supportive regulatory treatment" (*Id*, quoted at 6T 2025-26. See also 6T 2014).

Since the stable rating depends on supportive regulatory treatment, arguments inviting the Commission to rely on DTE Electric's tenuously stable credit rating (which assumes a continuing "supportive regulatory treatment") as a basis to withhold the necessary regulatory support are circuitous and would undermine the Company's credit rating. This is also a particularly inopportune time to weaken or neglect the Company's credit metrics due to the TCJA and the Company's need for capital spending, as discussed above.

Past concerns also continue to exist, as the PFD appears to have recognized. For example, in the current environment of low electric demand growth, DTE Electric's lack of a revenue decoupling mechanism or a fixed variable pricing policy places it at increased risk of under-recovering its cost of service relative to some companies in Dr. Vilbert's sample that benefit from such mechanisms (6T 1942-43). Moreover, in addition to ongoing uncertainty in the capital

markets discussed above, DTE Electric faces increased risk of under-recovery due to Michigan's economy, which is heavily dependent on the auto industry. DTE Electric's service territory is primarily in Southeastern Michigan including Detroit, which has a weak economy and declining and shifting population. DTE Electric also requires significant capital expenditures to comply with environmental requirements and has an asymmetrical risk (downside risk with no corresponding upside) due to the responsibilities of owning and safely operating a nuclear power plant. Therefore, DTE Electric has a higher-than-average business risk relative to companies in Dr. Vilbert's sample (6T 1945-48).

ii. Any reduction of equity in DTE Electric's capital structure would require a higher return on equity.

A company's cost of equity and capital structure are inextricably intertwined because the use of debt increases the company's financial risk, and therefore increases the Company's cost of equity. A lower equity ratio component (and a correspondingly higher debt component) in the capital structure creates a higher level of risk for shareholders and a corresponding need for a higher rate of return on equity. Dr. Vilbert's recommended ROE corresponds to a 51% equity ratio. Staff agreed, and the PFD's 50% recommendation should be rejected as discussed above. If DTE Electric has less equity as the PFD recommends, however (and a corresponding increase in both debt leverage as well as financial risk), then DTE Electric's ROE must increase to compensate for the increased risk (6T 1948, 1997-2008).

iii. Summary and Recommendations Regarding DTE Electric's Cost of Equity.

As discussed above (and further explained with detailed ROE analyses in DTE Electric's Initial Brief and Reply Brief, which the PFD did not address) a company of average business risk having a capital structure with 51% equity should have an ROE in the range of 9.75% to 10.75%.

DTE Electric has higher risk than the average sample company, so the corresponding ROE estimate for DTE Electric is 10.5% (6T 1975-76, 2016).

This is also important to maintain DTE Electric's access to capital. Maintaining a solid credit rating and outlook is one important aspect to maintaining access to capital. A supportive allowed return on equity is important to ensure the utility's favorable access to credit markets. Maintaining a strong credit rating is particularly critical during a period forecast to have substantial capital investment for infrastructure. In addition, it is expected that the cost of capital will increase as the Federal Reserve continues to adjust its monetary policy, so estimates at the upper end of the ROE range are more representative of the cost of capital expected going forward (6T 1976-77).

The PFD rejected the understated recommendations by Staff, the AG, and ABATE; however, the PFD neglected to fully appreciate the effects of recent and continuing changes in economic conditions and other factors that justify increasing DTE Electric's ROE to 10.5%.

V. DTE ELECTRIC'S ADJUSTED NET OPERATING INCOME AND REVENUE DEFICIENCY SHOULD BE ADOPTED.

DTE Electric projected its Total Electric adjusted Net Operating Income ("NOI") to be $801.7 million. The PFD recommends $847.4 million (PFD, Appendix C). DTE Electric takes exception to this and other matters as discussed below.

A. The Company's operating and maintenance ("O&M") expenses are reasonable and prudent and should be approved.

DTE Electric supports total O&M of $1,309.8 million (See Attachment A).

1. DTE Electric's Inflation on O&M Expense is reasonable and prudent and fully supported.

DTE Electric supports inflation rates of 3.0% for 2018, 2.9% for 2019, and 1.0% for January 1, 2018 through April 30, 2020 (Exhibit A-13, Schedule C5.15, line 15). These are composite rates using a 3.0% inflation rate for labor, and the consumer price index ("CPI")-Urban

for non-labor costs (7T 3302-3303). Staff "used inflation factors of 2.52%, 2.23% and 2.50% for 2018, 2019, and 2020, respectively," resulting in a $12,338,000 downward adjustment to O&M (Staff Initial Brief, p 65). The PFD adopted the Staff's proposed inflation rates by reasoning that the Commission previously rejected the use of a composite inflation rate (PFD, p 135). It is true that the Commission previously declined to adopt the Company's proposed composite inflation rate; however, the record in this case now compels adoption of DTE Electric's proposed composite labor/non-labor inflation rate by reflecting that the Company's labor costs are driven by collective bargaining agreements with unionized employees, as Mr. Cooper testified:

> Based on existing Collective Bargaining Agreements, the Company is obligated to increase base pay rates by approximately 3.0% annually through the term of the contracts. In addition to scheduled pay rate increases, the agreements also provide for progression increases for those employees that have not yet achieved the maximum pay rate for their positions [6T 1832.]

The 3.0% annual labor cost escalator reflects that existing collective bargaining agreements provide for annual increases of about 3.0% through the terms of the contracts and, also provide for progression increases for employees that have not yet achieved the maximum pay rate for their position. For employees not covered by collective bargaining agreements, it is expected that the annual overall pay increase program will be 3.0% for 2019 and 2020, just as it was in 2018 and every year since 2010. The specific increases are reflected on Exhibit A-32, Schedule V3, which reflects a summary of increases that was included in Part III, Part 5c, Attachment 6, Item 3 of the Company's initial submission (6T 1885-86).

There is no evidence that DTE Electric can avoid paying wage increases as set forth above, and any proposal that DTE Electric should do so anyway is not possible. DTE Electric cannot

violate its Collective Bargaining Agreements, and the Commission has no authority to become involved in or dictate results of collective bargaining. [28]

The PFD further suggested that "the company did not rebut that Staff's position, which recognizes that some inflation is likely to occur, but that productivity increases will offset higher labor inflation rates" (PFD, p 135). To the contrary, Mr. Stanczak explained that although the Company's ability to manage O&M in the past has been exceptional, the Company cannot continually reduce non-labor O&M to offset wage growth (3T 104). Therefore, the Commission should reject the PFD/Staff's proposed inflation adjustments and approve DTE Electric's proposed composite inflation rates.[29]

2. Distribution Operations O&M expenses.

DTE Electric supported $330.5 million of Distribution Operations' O&M expenses for the projected test period. This amount includes funding for DTE Electric's Enhanced Tree Trimming Program ("ETTP").

i. The Company's Enhanced Tree Trimming Program ("ETTP") and surge funding are reasonable and prudent and will provide significant benefits to customers.

DTE Electric intends to continue utilizing its ETTP, which removes significantly more vegetation in a clearance corridor rather than the historic clearance circle around DTE Electric's lines and equipment. The Commission approved the ETTP in Case No. U-17767, and increased funding to clear more miles of lines in Case Nos. U-18014 and U-18255. The ETTP needs to expand further to achieve a five-year trimming cycle because, as discussed in the Company's Five-

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[28] The Commission has no common law powers, but instead possesses only the limited authority that the Legislature conferred upon it. *Consumers Power Co v Public Service Comm*, 460 Mich 148, 155; 596 NW2d 126 (1999), *Mason Co Civil Research Council v Mason* Co, 343 Mich 313, 326-27; 72 NW2d 292 (1955).

[29] The PFD's adoption of Staff's inflation rates affects other issues and calculations. As indicated in the Introduction, DTE Electric takes exception to all of the results, but will not separately address each calculation or other consequence.

year Plan, tree interference is the leading driver of customer outages. Tree-caused outages account for two-thirds of the time that customers spend without power. No other program in the Company's portfolio of distribution projects will have a greater impact on mitigating risks, improving system and customer reliability, and managing the costs of operating the Company's distribution system. The Company's targeted five-year cycle is also comparable to the industry average of 4.9 years (3T 207-10, 221-22).

The Company requests $95.1 million of O&M for tree trimming in the projected test period (3T 223; Exhibit A-13, Schedule C5.6, line 18, column (l)).[30] This is not the total amount of funding needed to achieve a five-year tree-trimming cycle. DTE Electric also proposes a seven-year surge in tree trimming, but does not seek to recover surge expenses in its O&M levels in this case's revenue requirement. Instead, DTE Electric seeks approval to defer surge-related expenses as a regulatory asset and amortize it over 14 years.

Total forecasted tree-trimming costs are expected to be $1.3 billion from 2019 through 2025. Of this amount, $722 million is proposed to be recovered through base rates (the $95.3 million for the projected test year inflated at 3% per year), and $410 million is proposed to be deferred as a regulatory asset, and amortized over 14 years (3T 234-36; 7T 3336-37; Exhibit A-22, Schedule L3). The Company's proposal is appropriate because surge-related tree-trimming expenses will vary, so allowing the deferral of the expenditures above the level that is included in the rates approved in this case will ensure that customers only pay for work that is accomplished. The benefits provided by the surge will also continue for years after the work is completed. Allowing these costs to be deferred and then securitized with a 14-year amortization period will

[30] The Company's $95.1 million request consists of (1) $80.9 million for maintenance and staff (which is inflation-adjusted spending on the $77.5 million approved for this category in Case No. U-18255); (2) $12.2 million for reactive maintenance (which is inflation-adjusted funding based on 2017 historical spending of $11.2 million); and (3) $2 million for a herbicide program (3T 225-27).

better match those benefits to the recovery of the cost. Finally, DTE Electric intends to file a securitization application for the unamortized balance of the surge costs, which will lower costs to customers due to the lower cost of debt-only financing (3T 82, 235-36; 5T 1053-57).

ii. The PFD adopted Staff's modification, which is generally aligned with the Company's goals, but will increase the surge duration and prolong the recognition of long-term benefits.

Staff supported the Company's tree trimming goals – both the five-year trimming cycle for distribution circuits and the three-year cycle for sub-transmission circuits – and recognized the need for additional funding. However, Staff suggested cost recovery by increasing current funding through O&M expense, which means disallowing the $7,053,000 revenue requirement associated with the Surge and increasing Tree Trim Expense during the test year by $13,007,000, from $95,092,000 to $108,099,000. In the years following the test year, Staff suggested that the Company could request increases in spending on tree trimming until the backlog is eliminated and the five-year cycle is achieved, then drop the O&M amount to its forecasted amount in Exhibit A-22, Schedule L1 (Staff Initial Brief, pp 71-76, and 119). The PFD "recommends that the Staff's proposal, to remove the amortization cost from the company's rate request and increase tree trimming O&M expense from $95.1 million to $108.1 million is most reasonable and should be adopted" (PFD, p 147).

DTE Electric maintains that its surge program should be approved, since it provides additional customer benefits: (1) faster reduction of tree trim miles (seven years, rather than 8 years 4 months under the PFD/Staff's proposal), resulting in increased reliability and cost savings from reduced trouble and storm events; (2) smaller near-term rate increases and the alignment of rate increases with long-term future customer benefits; and (3) funding certainty will allow the

Company to enter into long-term contracts with tree trimming vendors, which are expected to provide more competitive pricing and greater labor availability and stability (3T 247-49).

If the Commission does not approve the Company's filed position, DTE Electric requests approval of one of the following alternatives:

(1) Approve regulatory asset treatment for the surge costs in the instant case and clarify that the Commission will address the appropriate amortization period in a future rate case.

(2) Provide additional O&M funding beyond that suggested by Staff. The Company requests $137.5 million of funding for the Tree Trim Program in the projected test year which would allow the Company to recover $119.6 million of tree trim expenses in the 2019 calendar year ($17.9 million less than the Company's requested surge funding for 2019). This amount would also help DTE Electric accelerate the needed tree trimming work by providing short-term funding certainty that is needed to secure additional tree trim labor (3T 249). Either of these alternatives would be a reasonable compromise between the Company's surge proposal and Staff's alternative funding proposal.

The PFD did not address the first alternative directly, but suggested that DTE Electric's financing proposals are too extensive (PFD, p 147). The Company maintains that the surge is the best way to address tree trimming, and that it is appropriate to address the best way to finance that program as a whole, rather than continue to revisit tree-trimming on a case-by-case basis. In addition to the discussion above, future ratepayers will also benefit from the improved reliability and decreased outages associated with the surge and a regular five-year tree trimming cycle (3T, 248). Therefore, amortization makes sense not only in the context of affordability for current ratepayers, but also to align payment of the costs with the receipt of the surge benefits.

The PFD rejected the second (O&M increase) alternative, reasoning "that $137 million would be a 64% increase in the tree-trimming budget at a time when there is significant uncertainty about the availability of tree-trimming labor in light of recent disasters" (PFD, p 147). While labor uncertainty does exist in the market, DTE Electric is confident that it will be able to spend, at a minimum, the $137,500,000 requested and has retained additional tree trimmers. [31] If the Company is unable to secure the funding requested to support its current spend trajectory then it will be forced to reduce the existing tree trim work force, delaying both the progress on the ETTP program and the associated reliability benefits that customers would experience. The PFD's suggestion that the Company's proposed funding increase is too large neglects that the current recovery reflects tree trimming "as usual." DTE Electric has proposed a new program – the surge – that requires additional funding to accomplish its objectives. If the Commission recognizes and agrees with the objectives of the surge, then the program should be funded adequately through O&M (if not through the Company's original proposal) so that the Company can achieve those objectives.

The future is always somewhat uncertain, but this should not stand in the way of attempting to implement the surge as the PFD suggests. Even though it cannot predict the future, the Company has appropriately *planned* for the future. DTE Electric will be transparent with surge program results and will make regular reports to the Commission that include surge tracking metrics and progress. The Company intends to work with the Commission and Staff to make appropriate modifications to the Surge program as actual results dictate (3T 250-51). The Company maintains that it has designed an appropriate tree trim program that is already providing significant customer benefits and will continue to provide increased benefits into the future.

[31] The Company has been able to secure over 1,150 tree trim contract employees who are actively working on the DTE Electric system as of March 19, 2019, up from 818 trimmers in June 2018.

History also reflects the Company's commitment to tree trimming and provides assurance for the future. Since 2009, the Company has spent $19 million more than approved amounts in rate cases, reflecting the Company's continuing focus on trimming trees maximize customer reliability (3T 252-53). The Company maintained a five-year trimming cycle through the end of 2013 while maintaining industry standard specifications. In 2014, the Company developed the ETTP, which essentially removes vegetation in a clearance corridor rather than the historic clearance circle around DTE Electric's lines and equipment. The Commission approved and increased ETTP funding in Case Nos. U-17767, U-18014, and U-18255. The Commission has also been fully informed in prior rate cases as indicated above, and recognized DTE Electric's spending and commitment in other proceedings.[32]

Finally, the PFD suggested that the Commission should consider (but made no recommendation on) a two-way tracker (PFD, pp 147-48). The Company prefers the Surge methodology to a two-way tracker because, as discussed above, it will allow for smaller near-term rate increases and will align these rate increases with long-term future customer benefits. If the Commission were to reject the Company's deferral and securitization proposal, DTE Electric is receptive to a two-way tracker as it would protect rate payers in the event of labor shortages and

[32] For example, the Commission opened an investigation regarding utilities' responses to the 2013 ice storm, which led to the May 2, 2014 and December 4, 2014 Orders in Case No. U-17542. The Commission recognized that trees are the primary cause of power outages, and that DTE Electric was spending all of its allocated funding for vegetation management to prevent such outages. The Commission stated in those prior orders, for example:

> The Staff recognizes vegetation management to be the most effective tool in outage avoidance and in limiting the duration of outages . . . With regard to DTE Electric, the Staff finds that its vegetation management program showed a strong commitment to staying 'on-cycle' and spending allocated funding on vegetation management. [May 2, 2014 Order in Case No. U-17542, pp 16].
>
> Both DTE Electric and Consumers state that the primary cause of damage and outages on their systems is contact from trees and other vegetation with utility infrastructure . . . DTE Electric reports that approximately 75% of the damage to its distribution system was caused by trees. DTE Electric is currently spending all of its allocated funding on vegetation management. [December 4, 2014 Order in Case No. U-17542, pp 4-5].

allow the Company an opportunity to accelerate the tree trimming plan if additional tree trim resources become available.

Therefore, the PFD's recommendation should be rejected, and the Company's tree-trimming requests should be adopted by the Commission. In the alternative, if the Commission agrees with the PFD recommendation, DTE Electric believes that a two-way tracker would benefit ratepayers and allow the Company to achieve its tree-trimming goals.

3. Customer Service O&M Expenses – meter reading expenses.

DTE Electric O&M expenses for the Customer Service organizations[33] include meter reading expenses. Staff proposed $1.483 million in O&M, which is $2.147 million less than the Company's $3.630 million proposal (Staff Initial Brief, pp 70-71). Staff explained that they "developed a meter-reading cost by applying the cost per meter reader in the historical period to the number of meter readers in the test year" to arrive at this level of funding (*Id*, p 71). The PFD agreed with Staff's methodology (PFD, p150).

The Company disagrees. Ms. Johnson explained that Staff's calculation is incorrect because Staff simply divided the 2017 Meter Reading O&M expense by 58 (the number of external vendors to read meters in 2017), and then multiplied that result by the number of external vendors to manually read meters in the projected test period and added inflation. Staff neglected that the O&M costs cover additional activities including billing operations pertaining to major accounts, metering operations, consecutive estimate team and special reading expenses. The PFD/Staff's

[33] The Customer Service organizations are Customer Contact Center, Customer Billing, Revenue Management and Protection ("RM&P") and Customer Experience. These organizations are responsible for billing, customer contact, and payment acceptance (7T 3110-12).

proposal should be rejected because it excludes these additional costs that the Company will incur (7T 3113, 3139-40).

4. The Company's projected uncollectible expense is accurate, reasonable, and should be approved.

i. The Company's calculation methodology should continue to be used.

DTE Electric supports $51.6 million of uncollectible expense based on a 2015-17 three-year average of actual uncollectible expense. Staff proposed to project uncollectible expense with a cash basis method using a three-year (2015-17) average of the ratio of net charges offs to revenue. Staff reasoned that the Company's "assumptions could result in significant forecasting error," yet proposed only a $234,000 reduction (Staff Initial Brief, pp 68-69). The PFD agreed with Staff, reasoning that Staff's method was used with other utilities and "appears more accurate and less prone to significant forecasting error" despite the $234,000 at issue (PFD, pp 154-55).

The Company disagrees with the PFD's recommendation. The most accurate method for forecasting uncollectable expense is using a three-year historical average of 2015-17 uncollectible expense as recorded in account 904, resulting in $51.6 million as indicated above. Ms. Uzenski explained that Staff's proposed cash-based methodology is flawed because there is not a direct correlation of the net charge offs and revenues used to calculate the ratio in any given year. There is a significant timing lag between revenue recognition and when the net charge offs occur. The Company uses a balance sheet method to accrue a reserve for the estimated portion of customer accounts receivable that will ultimately be written off (generally 150 days past final bill due date, which is issued after service is disconnected). The uncollectible expense recorded in the income statement reflects the change in the balance sheet reserve needed to reflect accounts receivable at a net realizable amount. In contrast, net charge offs relate to revenues earned in prior periods

without consideration of the age of the outstanding accounts receivable. Therefore, they are not representative of expense in the current period (7T 3346).

Staff's methodology is also inaccurate because the ratio of net charges offs to revenue was applied to the Company's present revenues to calculate Staff's projected uncollectible expense. Final revenues in the projected period will not be known until the conclusion of this case. Rates are set to cover the Company's estimated expenses to be recorded in the income statement. The estimation of future expenses should be consistent with the practice used to record the actual expenses. An average of the amounts charged to account 904 provides such consistency. The Commission has also consistently accepted the use of historical period uncollectible expense, as recorded in account 904, in past rate cases for both DTE Electric and DTE Gas (DTE Electric rate cases U-18255 and U-18014, and DTE Gas rate cases U-18999 and U-17999). (7T 3346-47).

Therefore, the Commission should reject the PFD/Staff's proposed alternative methodology, and maintain its appropriate methodology, resulting a projected uncollectible expense of $51.6 million as calculated by the Company (7T 3347).

ii. DTE Electric's proposed returned check charge should be approved.

DTE Electric has worked proactively to reduce uncollectible expense (7T 3124-26), and now proposes to use a third-party vendor to recover insufficient fund checks and increase the returned check charge from $15.00 to $28.66 (7T 3126-29). Staff did not oppose the Company's proposal to hire a third-party vendor, but recommended that the current $15.00 charge should be retained due to a concern about the impact such an increase would have on customers (Staff Initial Brief, p 146. See also Soulardarity Initial Brief, p 40). The PFD agreed, asserting that "DTE Electric's proposal simply increases the financial burden for those who can least afford to pay" (PFD, p 156).

The Company disagrees because it anticipates that the increased charge would deter customers from repeatedly writing checks that are returned for insufficient funds (7T 3129). Thus, by deterring repeated charges, the Company's proposal would result in the most-affected customers paying less in total.

5. Employee pension and benefits expense.

DTE Electric projects $161.9 million of employee pension and benefits O&M expense, which after adjustments results in a net employee pension and benefits expense of $146.9 million (6T 1831; Exhibit A-13, Schedule C5.10, line 32). In its Initial Brief, the Company also accepted an adjustment proposed by Staff Witness Welke to reduce active healthcare expense for the amortization of a one-time credit of $1.7 million (Initial Brief, p.83). While the PFD correctly states that no party objected to the Company's projected pension and Other Post-Employment Benefit (OPEB) expenses (PFD p.158), the PFD is silent on the other components of employee benefits expenses.

6. Employee compensation.

DTE takes issue with the PFD's proposed exclusion of the projected $27.1 million of cost related to the financial measures associated with the incentive compensation programs. The record supports the Company's position. In summary, the Company's overall compensation policy is to provide a competitive level of total compensation consisting of base pay plus incentive compensation. DTE Electric's incentive compensation programs for both its executive and non-executive employees consist of short-term incentive plans provided through the Annual Incentive Plan ("AIP"), applicable to executive level employees, and Rewarding Employees Plan ("REP"), available to all other non-represented employees. In addition, the Company provides a multiple year incentive plan delivered through the Long-Term Incentive Plan ("LTIP"), which is generally

available to managers and above, and up to 10% of other non-represented employees. Mr. Cooper provided a detailed description of the design and mechanics of these plans, including the metrics used to track Company performance, the method for setting Company performance level targets, and the conditions for payment of incentive compensation (6T 1842-51, 1865-77; Exhibit A-21, Schedules K1, K2, K3, and K4).[34]

DTE Electric seeks to recover the $46.4 million net projected test period expense of these plans, which excludes the incentive compensation expense allocated to the Company for DTE Energy's top five executives (Exhibit A-21, Schedule K5, line 63, column (k)). The components of these expenses are reflected in the table below, as differentiated for the portion of such expenses based on operating versus financial performance measures (6T 1852).

	LTIP	AIP	REP	Total
Financial	$15.4	$2.6	$9.1	$27.1
Operating	$0.0	$4.0	$15.3	$19.3
Total	$15.4	$6.6	$24.4	$46.4

Staff proposed to exclude $27,083,000, representing incentive compensation expense related to financial measures (Staff Initial Brief, pp 66-68). Staff acknowledged that it “did not introduce evidence that the Company’s overall compensation was unreasonable. Rather, Staff’s recommendation is based on the Commission’s Order in Case No. U-14347, which found that

[34] The performance measures included within these plans include both operating and financial metrics. The operating measures reflected in the short-term incentive plans relate to Customer Satisfaction, Employee Engagement and Operating Excellence, as appropriately customized for the specific business units. Within Customer Satisfaction are measures related to improving performance as measured by the J. D. Power National Peer Set. Also included are measures related to improving customer service and reducing complaints to the Commission. Employee Engagement pertains to creating a highly motivated and productive workforce as well as improvements related to workplace safety. Operating Excellence includes measures related to reducing the length of service interruptions, fossil and nuclear power plant reliability as well as additional specific measures related to the nuclear generation business unit. The Operating Excellence measures used at DTE Energy Corporate Services LLC were adjusted to exclude measures to DTE Gas (6T 1842-53).

when incentive compensation programs are tied to Company earnings and cash flow the plans largely benefit shareholders" (*Id*, p 68). Staff similarly suggested that it understood recent decisions by the Commission to have established a "policy" of excluding financial performance measures from the revenue requirement (8T 4049).

The AG proposed the complete elimination of incentive compensation expense related to financial measures ($27.083 million), plus 50% of incentive compensation expense related to operating measures ($9.649 million) for a total disallowance of $36.732 million (AG Initial Brief, pp 36-43). Like Staff, the AG's proposed exclusion of financial measures is based on a broad policy viewpoint that these measures benefit only shareholders and not customers (5T 1614-15).

The PFD found "that the Staff's recommendation to exclude the projected $21.7 [sic, $27.1] million cost of the financial measures associated with the incentive compensation programs should be adopted" (PFD, p 169), essentially reasoning that little has changed since the Commission excluded the cost of financial measures in Case No. U-18255 and suggesting that the quantified customer benefits of the financial related measures are "attenuated at best, and in some cases, specious" (PFD, pp 169-72).

The Company disagrees with the PFD's assertion that little has changed since the Commission excluded the cost of financial measures and that the quantification of the customer benefits are flawed. The Company maintains that the Commission must base its decision on the record, and the record in this case fully supports the Company's proposed recovery.[35] The

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[35] The Commission has based its decisions on the evidence (*e.g.*, April 17, 2018 Order in Case No. U-18255, p 49) and has expressly recognized that "each case must be evaluated on the record in that case" (January 31, 2017 Order in Case No. U-18014, p 85). Michigan's Constitution requires the Commission's findings to "be supported by competent, material and substantial evidence on the whole record." Const 1963, art 6, § 28. The APA similarly precludes the Commission from making decisions based on non-record materials. MCL 24.276.

Commission's older orders also recognize that incentive compensation is recoverable based on the type of programs that DTE Electric has developed and the type of evidentiary record that DTE Electric has presented in this case.[36] The PFD's proposed exclusion of the incentive compensation expense related to financial measures dismisses the substantial quantified customer benefits related to financial measures reflected within the cost/benefit analysis on Exhibit A-21, Schedule K5, and further explained by Mr. Cooper. Financial metrics do not simply benefit shareholders. Instead, customers benefit from incentive compensation measures that motivate employees to focus on earnings and cash flow measures because the ability to exceed the annual goals is dependent on the Company realizing productivity enhancements and cost savings, allowing the Company to postpone rate increases and producing lower revenue requirements when rate increases become unavoidable. Ultimately, this also provides higher quality customer service. It is logical that if a company wishes to create a performance-based culture through the use of variable pay programs designed to motivate the organization's overall effectiveness, financial metrics are often used to provide a common driver and have the advantage of being measured on a comprehensive, timely and comparable basis.

[36] The Commission long ago recognized that: "Executive bonuses have often been viewed as an appropriate cost of operating a utility" (October 28, 1993 Opinion and Order in Case Nos. U-10149 and U-10150, p 57 (rejecting the ALJ's total exclusion recommendation; adopting Staff's 50/50 sharing proposal; and advising DTE Gas that "future approval of an incentive bonus plan like this requires a showing that it will not result in excessive costs and that the benefits to the utility's ratepayers will be commensurate with those costs"). See also, for further example, Case No. U-17767, where the Commission approved DTE Electric's recovery of costs attributable to operating measures, stating that:

> [I]n the immediate case, the Commission finds that DTE Electric provided convincing evidence that the operating (non-financial) measures for the AIP and REP provide appreciable benefits to customers, and meet the standard set forth in the April 28, 2005 order in Case No. U-13898 (April 28 order) and the December 23, 2008 order in Case No. U-15244 (December 23 order) . . . . [December 11, 2015 Order in Case No. U-17767, p 76.]

Financial based measures motivate employees to improve their work processes to use fewer resources while producing improved performance. The beneficial impact of the cost and productivity focuses of the earnings related measures is illustrated by the fact that the Company's O&M expenses have increased by dramatically less than inflation from 2009 through the end of the projected test year. Indeed, the Company's projected O&M expense as filed for the projected test year is $226.2 million less than it would have been if the Company's 2009 O&M expense increased by the Consumer Price Index, translating to a $21.9 million annual benefit, as reflected on Exhibit A-21, Schedule K-5. The PFD concludes that this benefit is merely an incentive for the Company to spend $21.9 million annually less than the level of O&M included in the revenue requirement (PFD p. 172). This conclusion misses the point of the analysis. As an electric utility, DTE Electric has little direct control over its revenue; the Commission sets its rates and the Company's sales levels are largely dependent on regional economic activity and the weather. Because the Company does not control either of these factors, its primary ability to improve its financial performance is through effective cost control. Mr. Cooper's demonstration that the Company's actual and projected O&M from 2009 through the end of the projected test year will increase less than inflation illustrates how customers have and will continue to receive the benefit of the Company's reduced revenue requirement made possible through the effective management of costs. While Mr. Cooper concedes that salutary effects of the Company's superior financial performance made possible through improved cost efficiencies may result in temporary benefits to shareholders, the benefits to customers of these improved efficiencies are permanent as revenue requirements reflecting these lower cost levels are adopted by the Commission. Since the establishment of the revenue requirements in this and subsequent cases is based, in part, on historical costs, the long-term benefits to customers will exceed the short-term benefits to

shareholders. This customer benefit is unrelated to the Company's actual cost levels in the future, as incorrectly presumed in the PFD.

DTE Electric's cash flow related measures directly affect its ability to raise capital, and the cost of capital, that it needs to fund its operations. Mr. Cooper testified that the benefits of the Company maintaining its existing credit ratings avoids a $15.6 million increase in its annual interest costs. The PFD concludes that it is inappropriate to attribute the benefits of the Company's credit ratings to the incentive compensation programs because it ignores the costs charged to ratepayers and cites the income requirement adopted by the Commission in its Order in Case No. U-18255 (PFD p.172). While the Company's revenue requirements are borne by its customers, there is no evidence that the Company's customers are required to bear any excess costs arising from the its capital structure. Indeed, as explained by Dr. Vilbert, any increase in leverage would increase the Company's cost of equity (6T 1948). Moreover, the benefits of an employee emphasis on cash flow are similar to the earnings measures. On a day-to-day basis, the Company has little control over revenues, as described above, but it can control how it uses its resources. While the earnings benefit quantification was based on the ability to limit the growth in O&M expenses, the cash flow measures are designed to provide a focus on effective management of the Company's capital spending program, as cash flow reflects, among other things, capital expenditures. Furthermore, DTE Electric's shareholders are also sharing in the incentive compensation expense, since the Company's proposed recovery does not include $10.0 million of incentive compensation expense for the top 5 executives (6T 1838-41, 1853-56, 1866-67; Exhibit A-13, Schedule C-17).

Beyond the mechanics of the demonstration of the net customer benefits, the propriety of the Company recovering all if its incentive compensation expenses, inclusive of both operating and financial measures, is the overall reasonableness of the resulting total compensation. DTE

Electric must also offer incentive compensation opportunities to be competitive with other employers in attracting and retaining talented and qualified employees (6T 1833, 1841). The PFD's focus on the variable portion of total compensation is also inappropriate because DTE Electric's incentive programs are not additional compensation over and above what other companies pay for similar jobs. Instead, DTE Electric's incentive compensation programs are one of two components that comprise DTE Electric's total annual compensation package, which is comparable to other companies competing for the same employees (6T 1832-34). The most recent study (as of December 31, 2017) determined that total compensation for non-represented employees exclusive of executives was less than the market median for all matched positions (6T 1868; Exhibit A-32, Schedule V1). Similarly, based on a recent Aon Hewitt survey of DTE executive compensation compared to its peer companies, the total compensation, including incentive compensation, for DTE is about 4% less than the peer group based on target performance levels (6T 1841-42, 1868).

Without the prospect of total annual compensation equal to the fixed plus the variable compensation components, DTE Electric would not be able to attract and retain a highly-skilled workforce, or provide incentives for its employees to engage in activities that benefit customers because total compensation would be substantially less than the peer companies. Incentive compensation is just part of total compensation.

In summary, DTE Electric's proposal to include incentive compensation expense related to both the operating and financial measures is fully supported by the record in this case as DTE Electric provided an in-depth cost/benefit analysis demonstrating a $77.3 million net customer benefit ($123.7 million total customer benefits minus $46.4 million total incentive plan costs). (6T 1854-61; Exhibit A-21, Schedule K5, line 63). DTE Electric has demonstrated in detail that the customer benefits of its incentive compensation plans significantly outweigh their costs, that the

total compensation is reasonable based on comparison to the Company's peers, and that there is no valid reason to disallow the portion of incentive compensation related to the financial measures. Therefore, based on the evidence in this record, the Commission should reject the PFD's exclusion of $27.1 million of incentive compensation expense and approve DTE Electric's request to include all of the Company's incentive compensation expense (except for the top five DTE Energy executives) in the revenue requirement adopted in this case.

7. Edison Electric Institute Dues

DTE Electric included in its projected O&M expense $1.3 million related to dues paid to Edison Electric Institute (EEI). MEC/NRDC/SC recommended that $1,269,000 in dues that DTE Electric pays to EEI, and charges to ratepayers, be disallowed. According to Mr. Rábago, DTE Electric belongs to many trade associations, including EEI, however, "[u]nbeknownst to most customers, these payments may be used to fund advocacy with which customers may disagree and that is contrary to their interests." Mr. Rábago explained that some portion of EEI dues, the part associated with the organization's lobbying efforts, is excluded from O&M expense, but that amount is determined by EEI and reported to DTE Electric on EEI's invoice. Mr. Rábago concluded that, "[t]he Company has failed to demonstrate that the costs associated with EEI membership dues are limited to activities that benefit ratepayers and therefore are just and reasonable. The PFD recommends adopting MEC/NRDC/SC's proposed disallowance of EEI dues in the amount of $1,269,000 absent any evidence from DTE Electric rebutting Mr. Rábago's testimony.

Mr. Rabago did not provide any specific evidence that the EEI dues included in the Company's projected O&M related to lobbying activities other than stating the amount is determined by EEI. As stated in Mr. Rabago's testimony, the Company does exclude a portion of

the EEI dues from O&M expense. DTE Electric has consistently relied on invoices from EEI for properly recording recoverable and nonrecoverable dues on its books and has no reason to believe the amounts provided to us by EEI are inaccurate. Even though Mr. Rábago discussed several efforts that EEI undertakes that clearly provide ratepayer benefits, including workforce education and training, public safety campaigns, and EEI's mutual assistance program, he proposed disallowing 100% of EEI dues. MEC/NRDC/SC's recommendation is not justified and the PFD's recommendation to disallow $1.3 million of EEI dues should be rejected.

8. Weekend Flex and Fixed Bill O&M expense

DTE Electric is proposing to include $0.4 million and $1.0 million in O&M expense for the Weekend Flex and Fixed Bill pilot programs respectively. The ALJ's recommendation to disallow these amounts are discussed in detail in Section VI.E.

B. Depreciation and Amortization.

DTE Electric's projected depreciation and amortization ("D&A") expense is $883.5 million.[37] The PFD recommends $875,900,000 based on the PFD's proposed disallowances (PFD, p 174, citing Appendix A, p 3, (but note that this cite does not exist). DTE Electric takes exception and maintains that the Commission should approve the Company's projected D&A expense of $883.5 million, incorporating the discussions in these Exceptions regarding the PFD's proposed disallowances.

[37] DTE Electric's Initial Brief, pp 91-92, explained and supported the Company's projected depreciation and amortization ("D&A") expense of $883.6 million, which is based on the $948.986 million filed amount minus $65.2 million (due to new depreciation rates from the December 6, 2018 Order Approving Settlement Agreement in Case No. U-18150, p 3), and $151,000 (due to a $4.5 million reduction to the Company's capital projections), as discussed in Section I of DTE Electric's Initial Brief. DTE Electric's Reply Brief made an additional $89,000 reduction to depreciation to properly remove depreciation related to HQ Energy Center contingency at the approved U-18150 depreciation rate. ($240,000 less $151,000).

C. Federal Income Tax Expenses.

The PFD does not make an explicit recommendation regarding federal income tax ("FIT") expense, but implicitly suggests adopting the level resulting from Staff's adjustments to the Company's projected revenues and expenses (PFD, p 175). DTE Electric maintains that the PFD/Staff's proposed adjustments should be rejected as discussed in these Exceptions, with corresponding tax effects.

D. Allowance for funds used during construction (AFUDC) and Other Operating Income Adjustments.

DTE Electric included $32.973 million in total as an AFUDC operating income adjustment. Staff recommended increasing AFUDC by $1.923 million to $34.896 million (Staff Initial Brief, p 79). The PFD did not address this matter, but implicitly made Staff's proposed adjustment, which is reflected at PFD Appendix C, line 22. DTE Electric maintains its position. Staff did not disagree with the Company's inclusion of CWIP for ratemaking purposes and would note that by AFUDC being in CWIP, it too, is part of CWIP allowed for ratemaking purposes. However, Staff did disagree with the inclusion of AFUDC in CWIP without an offsetting adjustment to operating income. Without an offsetting adjustment to operating income the Company would be earning a return of $2,594,975 on its financing costs (AFUDC) (Exhibit S-9.0) and thus, Staff argued, would burden the ratepayer with providing the Company recovery of its financing costs prior to those costs being closed to plant in service (Staff Initial Brief p 80).

Ms. Uzenski testified that this argument confuses two different concepts – AFUDC and return on rate base (7T 3351). The Company's accounting practice complies with the Commission's Order in Case No. U-5281 because it does not record additional AFUDC on the AFUDC included in CWIP – *i.e.*, no compounding. The Order in Case No. U-5281 does not state that a return on CWIP, inclusive of AFUDC, is excluded from rate base. In fact, one of the objectives of the Order in Case

No. U-5281 was to clarify that CWIP is to be included in rate base. In addition, once CWIP is transferred to plant in service, a return is earned on the entire plant balance, including capitalized AFUDC. It would be inconsistent to allow a return on capitalized AFUDC in plant, but not on AFUDC in CWIP. The Company's method for determining the AFUDC credit for rate-making purposes is consistent with the order and the practice used in prior rate cases (7T 3351). The Commission should reject the PFD/Staff's adjustment and approve the Company's AFUDC amount of $32.973 million.

E. Charging Forward

The Company proposes the Charging Forward program to advance on-road transportation electrification (see generally, DTE Electric's Initial Brief, pp 95-102). The PFD reflects that the other parties generally agreed that the Company's proposal is beneficial and appropriate, and that the Company agreed to several specific program changes suggested by other parties (see generally, PFD, pp 175-81; the agreed-upon changes are also listed at DTE Electric Reply Brief, pp 131-33). The Company, however, disagreed with several of the modifications proposed by different parties, and maintains its disagreement to the PFD's recommendation of those changes. Therefore, the Company's Charging Forward proposal, with only the modifications agreed upon by the Company, should be approved.

1. The PFD's recommendation to allow site hosts to charge by the kilowatt-hour should be rejected.

Staff, ChargePoint, ELPC, MEC/NRDC/SC, and EIBC/IEI requested that the Company modify its current tariff rules to allow site hosts to charge by the kilowatt-hour (*i.e.*, remove the "sale-for-resale" prohibition). The PFD agreed, and after quoting MEC/NRDC/SC at length, stated:

> The Staff's and Intervenor's evidentiary presentations and arguments on this issue are convincing. A properly structured EV program must free site hosts from the confines of DTE Electric's sale-for-resale prohibition. In short, DTE Electric's

> proposal to retain its sale-for-resale prohibition would remove a valuable tool from Charging Forward's toolbox of pilot program options that should be available to site hosts and DTE Electric. The reasons for this conclusion are numerous and nicely summarized by MEC/NRDC/SC, quoted above, and will not be repeated. Lifting DTE Electric's sale-for-resale prohibition is necessary if DTE Electric wishes to properly explore and learn how to best manage the demands of the electrification of the automotive sector. [PFD, pp 193-94. Footnote omitted.]

The Company strongly disagrees for multiple reasons. Volumetric pricing is an imprecise signal to the customer and is not necessarily correlated with the Company's fixed and demand-based investments. In addition, allowing site hosts to charge services by the kilowatt-hour could create confusion for customers (i.e., EV drivers) as the rates to be offered by the site hosts would not be regulated by the Commission and could be quite different than those offered by the utility (i.e., a customer could call DTE Electric and ask why he/she is being charged 30 cents per kilowatt-hour when the price they pay for electricity at home is much lower).

Furthermore, the Company believes that there are multiple options for DTE Electric to collaborate with site hosts to ensure that the pricing for the charging services reflect the conditions in the electricity system. Limiting a site host to charge on a per kilowatt-hour basis, will mask the pricing approach that a site host could pursue as it tries to price the interrelated services it provides and the investments that it is trying to recover through its pricing strategy as, of course, the site host would also be providing the parking space, billing interface, and potentially other parking-related services along with the charging functionality.

DTE Electric has proposed the EV program its management believes is appropriate. In *Union Carbide v Public Service Comm*, 431 Mich 135; 428 NW2d 322 (1988) our Supreme Court explained:

> The power to fix and regulate rates, however, does not carry with it, either explicitly or by necessary implication, the power to make management decisions.
> 'It must never be forgotten that while the State may regulate with a view to enforcing reasonable rates and rates, it is not the owner of the property of public

utility companies and is not clothed with the general power of management incident to ownership.' *Missouri ex rel Southwestern Bell Telephone Co v Public Service Comm*, 262 US 276, 289; 43 S Ct 544, 547; 67 L Ed 981 (1923)." 431 Mich at 148-49. *See also Consumers Power Co v Public Service Comm*, 460 Mich 148, 157; 596 NW2d 126 (1999).

DTE Electric appreciates the input and collaboration regarding EV service but does not wish to implement proposals involving per kWh pricing for EV charging. It bears emphasis that the proposals (and now the PFD's recommendation) to remove the "sale-for-resale" provision are contrary to the fundamental business structure that the Company envisioned for the Charging Forward program. The Company does not agree to such proposals, and the Commission should not order the changes set forth in these proposals. The PFD disagreed stating:

> DTE Electric's argument and reliance on *Union Carbide* is not convincing. In *Union Carbide*, the Commission was found to have exceeded its authority when it ordered Consumers energy to cease operation of its Karn units No. 3 and No. 4 out of economic order. However, the same court also found that the Commission was within its authority to regulate to enforce reasonable rates and charges and that it may prevent the passing through to customers of any unreasonably incurred expense. In this case, the Commission is called upon to amend a DTE Electric tariff provision that Staff and Intervenors find unreasonable. Pursuant to *Union Carbide*, the Commission has full authority to grant that request. [PFD, pp 194-95. Footnotes omitted.]

This interpretation misreads *Union Carbine* to suggest that anything involving "rates and charges" is within the Commission's authority. But the Commission's authority is limited. [38] The Commission has "ratemaking" authority, but almost any aspect of DTE Electric's business the

[38] The MPSC has no common law powers, but only possesses the limited authority that the Legislature conferred upon it. *Consumers Power Co v Public Service Comm*, 460 Mich 148, 155; 596 NW2d 126 (1999). The MPSC is an "administrative body created by statute and the warrant for the exercise of all its power and authority must be found in statutory enactments." *Union Carbide v Public Service Comm*, 431 Mich 135, 146; 428 NW2d 322 (1988); *Sparta Foundry Co v Public Utilities Comm*, 275 Mich 562, 564; 267 NW 736 (1936). The MPSC's authority must be conferred by clear and unmistakable statutory language, and a doubtful power does not exist. *Mason Co Civil Research Council v Mason Co*, 343 Mich 313, 326-27; 72 NW2d 292 (1955). The MPSC cannot expand its jurisdiction through its own acts or assumption of authority. *Ram Broadcasting v Public Service Comm*, 113 Mich App 79, 92; 317 NW2d 295 (1982). The MPSC cannot re-write the Legislature's language to include new or different provisions. *Hanson v Mecosta Co Rd Comm*, 465 Mich 492, 501-503; 638 NW2d 396 (2002). If an MPSC order conflicts with a statute, the order is void. *Manufacturers Nat'l Bank v DNR*, 420 Mich 128, 146; 362 NW2d 572 (1984).

Commission regulates may affect rates to some degree, and the Commission cannot expand its authority by mischaracterizing its decision as "ratemaking." *See Consumers Power Co v Public Service Co*, 460 Mich 148, 157-58; 596 NW2d 126 (2004) (rejecting MPSC's "ratemaking" defense and vacating the MPSC's order as unlawful).

In this case, the PFD recommends changing DTE Electric's proposed Program. This unlawfully encroaches on utility management, as illustrated by *Ford Motor Co v Public Service Comm*, 221 Mich App 370, 385, 387-88; 562 NW2d 224 (1997), where DTE Electric proposed a demand side management ("DSM") program. The Commission modified that proposed program (much like the PFD recommends here). The Court of Appeals held that the Commission's modification of DTE Electric's DSM program was unlawful, explaining in part: "The PSC here exceeded its ratemaking authority by, in effect, requiring Detroit Edison's management to adopt the DSM program the PSC thought best. The PSC did significantly more than 'approve' the DSM program proposed by Detroit Edison." 562 NW2d at 234-234. See also *Attorney General v Public Service Comm*, 269 Mich App 473; 713 NW2d 290 (2005) (MPSC exceeded its authority when it ordered the utility to expand its "green power" program and required customers who did not participate in the program to subsidize its costs).

There is also a well-understood electric regulatory paradigm that must not be upended by engaging multiple independent agents in activities that might be confused with the provision of regulated electric service. Only customers qualifying for DTE Electric's Rider No. 4 ("Resale of Service") may engage in the resale of service under limited circumstances, and those customers who qualify for Resale of Service are obligated to charge the current rates of the utility and otherwise conform to various service requirements (8T 3617).

Therefore, and in addition to the other reasons discussed above, the well-understood and non-problematic sale-for-resale probation should remain in place.

2. The PFD's proposed regulatory asset treatment and amortization would cause the Company to lose recovery of deferred costs that are amortized without the expense being included in the revenue requirement

Staff recommended reducing incremental Charging Forward O&M expense by $1,168,000 (Staff Initial Brief, p 70), and that the Commission adopt Staff's proposal for regulatory asset treatment and amortization rather than the Company's proposal (Staff Initial Brief, pp 117-19).[39] The Company agreed with the use of account 182.3 for the rebates, and amortization over five years, which are consistent with the Company's requests to use account 182.3 and to recover the deferred costs over five years by including the amortization expense in O&M, as shown on Exhibit A-13, Schedule C5.8, column (i), line 12. The Company disagreed with Staff's proposals to (1) begin amortization the year after the costs are incurred, and (2) delay recovery of the unamortized balance until after Staff's review (7T 3330, 3348).[40] The PFD agreed with Staff, stating:

> In the case at bar, considered as a whole, and recognizing the uncertainty of Charging Forward's actual costs, the Commission finds Staff's proposal most reasonable. A Staff argues, it protects customers from paying for costs that might not be incurred and provides DTE Electric to fairly recover its costs actually incurred. This is particularly important considering DTE Electric's track record of slow EV pilot program implementation. Additionally, it has the added benefit of being consistence [sic] with the EV provisions of the Commission's January 9th orders in Case No. U-20134. Therefore, it is recommended that the Commission approve the regulatory asset treatment of Charging Forward deferred costs, with a five-year amortization beginning the year following cost deferral, and allowance in rate base and expense after a prudency review in future DTE Electric rate cases. And, as it did in the Consumers Energy case, it is recommended that the

[39] More specifically, Staff proposed the use of account 182.3, Other Regulatory Assets, for the rebates and certain capital and O&M costs; amortization of the regulatory asset over five years beginning the year after the costs are incurred; inclusion of prudent costs in base rates after a review by Staff; and inclusion of the net unamortized balance of the reviewed costs in rate base (8T 4056).

[40] The Company also disagreed with Staff's proposal to include capital expenditures in the regulatory asset because they are more appropriately classified within Property, Plant and Equipment, as outlined in the Commission's Uniform System of Accounts. However, to minimize the number of arguments related to the Charging Forward project, the Company will accept the classification specified in the final order in this case.

> Commission direct DTE Electric to examine whether there would be cost savings realized by use of a tracker for future rebate programs. [PFD, pp 213-14.]

Regarding the PFD/Staff's first proposal (concerning when amortization begins), Ms. Uzenski explained that the Company would lose recovery of deferred costs that are amortized without the expense being included in the revenue requirement. If the Commission approves the proposed IRM, then DTE Electric might not file another rate case for a few years. Therefore, a portion of the deferred costs will be amortized but never recovered. The unrecovered amount would be even larger if the Commission accepts Staff's adjustment to remove the Company's forecasted amortization expense from the projected period in this case. The Company's support of the EV market will benefit all customers, not just those owning EVs (see generally, DTE Electric's Initial Brief, p 100, and PFD, p 176, n 400: "[I[t is agreed by all that the near-term electrification of the auto sector is a near certainty with enormous benefits."). Therefore, the Company should not have to absorb the expenses for the Charging Forward program. Thus, the costs deferred to the regulatory asset should remain in that account until the amortization expense is reflected in base rates (7T 3348-49).

In its initial brief, Staff agreed that some costs might not be recovered due to regulatory lag. Staff also correctly noted that depending on the timing of DTE Electric's future rate cases, the Company could over-recover some of the costs. The Company stated in testimony a willingness to provide Staff with a reconciliation of the actual costs incurred to the amounts included in the revenue requirement as part of Staff's audit in the next rate case. This could address the Staff's concern regarding over-recovery.

Regarding the PFD/Staff's second proposal (to delay recovery pending Staff's review), the Company agrees that a prudency review by Staff is appropriate, but depending on the timing of future rate cases and Staff's reviews, recovery of the deferred costs could be significantly delayed. This would be even more troublesome if amortization expense starts the year after the costs are incurred

(as discussed above) because some costs would not be recovered at all. For example, as shown on DTE Electric's Exhibit A-12, Schedule B5.9, the Company forecasted 2019 costs of $2.8 million, 2020 costs of $5.1 million, and $5.2 million in 2021, totaling $13.1 million. Staff's proposed treatment would have the Company expense $0.5 million starting in 2020, increasing to $2.6 million annually in 2022 without any recovery ($13.1 million / 5 years). Even if the Company filed its next rate case in 2019 or 2020, the Company would continue to lose a portion of the annual amortization because the Staff would not be able to audit all 2019 or 2020 costs before they completed their testimony. Overall, the PFD/Staff's proposed accounting is a disincentive for the Company to aggressively implement the Charging Forward program.

The Company wants to proceed with Charging Forward - which received support by all parties - and the Company believes having the Commission approve the costs now is the most prudent way forward. Charging Forward represents a program that is proactive and innovative and that seeks to provide benefits to all utility customers by ensuring the additional load of the system does not trigger additional investments. The Company believes that it should have an incentive to help drive increased adoption thorough the deployment of an appropriately sized program. The Company does not believe that it should bear a higher risk of cost recovery for a new program like Charging Forward. Furthermore, the costs for Charging Forward are relatively straightforward (primarily rebates where the amounts per rebate have already being provided by the Company), thereby minimizing the risk of Staff identifying material amounts of imprudent expenditures. Therefore, the Company proposes that the net regulatory asset and the related amortization expense be reflected in the projected test period, as proposed by the Company. The Company can provide Staff with a reconciliation of the actual costs incurred to the amounts included in the revenue requirement as part of Staff's audit in the next rate case. Any additional costs incurred after the projected period should remain on DTE Electric's

balance sheet for recovery in the next rate case (7T 3349-50). The Company believes this is a reasonable and fair proposal that should be adopted by the Commission.

3. Staff's proposed regulatory asset treatment for O&M costs should be rejected and O&M should be recovered as base O&M.

The PFD states: "DTE Electric agrees with Staff's position to give Charging Forward O&M expense regulatory asset treatment with amortization over five years" (PFD, p 211). To the contrary, the Company proposed that O&M expenses (primarily customer outreach and program management within marketing) should not be deferred, but instead be recovered as base O&M (See PFD, p211). DTE Electric maintains its position, which the PFD apparently just misunderstood. The use of a projected test period also plainly allows the recovery of costs to be incurred in the future. The Company is expecting to begin the process of hiring new employees to help support the deployment of the Program, and the lack of certainty on cost recovery could delay the implementation of this aspect of the program. The Company has already provided, as part of the record on this case, the specific O&M costs and the purpose for those costs. No party has disputed the need for the activities associated with the O&M recovery. The Company can (as with the regulatory asset costs) provide Staff with a reconciliation of the actual costs incurred to the amounts included in the revenue requirement as part of Staff's audit in the next rate case. Any additional costs incurred after the projected test period should remain on DTE Electric's balance sheet for recovery in the Company's next rate case. (7T 3349-50).

4. Additional pilot elements should be rejected, so there is no need to increase the Charging Forward budget; however, any increase in program cost must have a corresponding cost recovery.

The complete implementation of Charging Forward as proposed by the Company is expected to cost approximately $13 million, including O&M, through the end of 2021 (8T 3579; Exhibit A-12, Schedule B5.9). Staff proposed a $6 million increase in the Company's requested

funding, for a total of $19 million to cover expanded piloting (Staff Initial Brief, p 103)[41]. The PFD agreed, stating:

> As discussed above, this PFD recommends that the Charging Forward program be expanded in scope in several significant ways. For example, it is anticipated that an expanded school bus pilot will add cost, the amount yet to be determined. It is possible that removal of rebate caps could also add costs. Additionally, to establish a minimum network of corridor chargers, DTE Electric may need more than the 32 DCFC that it proposes. Also, DTE Electric indicates that it will be rolling in the costs of its delayed 2018 EV pilots. And, finally, DTE Electric may find that it has underestimated the human resources it will need committed to the program and the large undertaking it represents. In sum, there is sufficient evidentiary support to conclude additional funding will likely be needed to make Charging Forward the success all parties to this case hope for and the Michigan citizenry needs.. [PFD, pp 209-210.]

The Company believes it is premature to increase funding and prefers to ensure it is on target to implement a successful program before it proposes increases in scope and budget to Charging Forward. The structure and budget for the Charging Forward program were carefully planned and the Company has not assessed the requirements related to the PFD's additional recommendations (plus other pilots and suggestions by Staff and other parties).[42] As such, the Company does not have any basis to determine whether the incremental $6 million in budget is adequate or not. The Company does not understand what specific objectives are going to be answered by the other proposed pilots that cannot be answered by its own Charging Forward program (or learnings to be gleaned from programs across the country).

With respect to the school bus pilot, the PFD stated:

> The Staff's recommendation is well taken. Charging Forward is, in large part, a collection of pilot programs designed to inform DTE Electric and the Commission about, among other things, EV consumer behavior, EV technical issues, and the costs and benefits related to the electrification of Michigan's transportation sector. School buses are certainly an important part of that sector and potentially represent a storage resource to be integrated into the grid. Recognizing that significant

[41] However, $13 million plus $6 million totals $19 million rather than $18 million.

[42] The Company assumes that other parties will file Exceptions advocating additional program changes.

> additional costs are likely associated with Staff's expanded School Bus Pilot program, it is, none-the-less very important that this option be explored. In addition, it is equally important that the financial risks associated with piloting the new technologies involved not fall on our schools. Therefore, it is recommended that the commission adopt Staff's proposal for an expanded Scholl Bus Pilot program. [PFD, pp 183-84.]

In a footnote, the PFD added:

> While DTE Electric has great leeway in formulating a School Bus Pilot Program, the Commission envisions DTE Electric providing significant financial and technical support to the participating schools to ensure that schools, who are essentially serving as guinea pigs in a larger EV experiment, are held financially harmless. [PFD, p 184, n 444.]

DTE Electric agrees that a school bus pilot is important – that is why the Company proposed one. The Company also appreciates the intent behind the PFD's recommendation; however, the PFD's recommendation is premature. Overall the Company supports the proposal to incorporate additional pilot elements into the school bus category, but the Company's initial objective will be to find school districts that are willing to add electric buses to their fleets. Once the school district(s) are identified, the Company will work collaboratively to determine potential pilot scope additions and evaluate the related costs and benefits within the available program funding. In addition, the Company will work with the school district to identify sources of funding other than DTE Electric. Therefore, the Company believes it is premature to request additional expenditures and Charging Forward activity related to school bus electrification (8T 3615).

In a broader sense, for the different pilot proposals that Staff and other parties have suggested, the Company has already provided insights into how those elements can be included in the Program as currently designed and proposed.[43] The Company is concerned that by adding a

[43] The PFD recommended that the Commission take no action on Staff's recommendation that the Commission approve an 80 Amp charging pilot (PFD, pp 185-86). The Company supports 80 Amp charging, but does not believe that an additional piloting element is necessary to properly promote the concept. The Company will educate customers on this available technology as part of its site host acquisition strategy. Any site host that requests this new

significant focus on pilots, the benefits to all of DTE Electric's customers will be reduced. The Commission's recent EV decision in Consumers Energy's rate case further indicated that "EV adoption is in its infancy in Michigan, but all indicators point to continued expansion. This expansion may result in increased load, but it may also result in more efficient use of excess generation and distribution capacity during off-peak hours to the benefit of all customers, as well as provide new modes of storage. None of this will materialize until EV chargers become more prevalent and accessible" (January 9, 2019 Order in Case No. U-20134, p 8). DTE Electric agrees that the key element at this stage of development is to increase the prevalence and accessibility of chargers which is the focus of Charging Forward, and not on a broad and all-encompassing view on all the potential pilots that could be pursued. Finally, and based on its analysis of lessons learned from the initial stages of Charging Forward, market developments and learnings from research efforts such as DOE's US Drive – of which DTE is a member-, the Company might propose changes in scope and funding in future rate cases that might include new and additional piloting elements (8T 3613).

That said, if the Commission does expand the scope of the Charging Forward program as the PFD recommends (or otherwise), then the Company is entitled to cost recovery. Rates for utility service are based on the estimated costs of providing that service, plus a reasonable return on the utility's investment. *ABATE v Public Service Comm*, 208 Mich App 248, 257-258; 527 NW2d 533 (1994). This is part of the "regulatory compact," under which the utility dedicates its private

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technology will be able to receive it when it meets the connectivity and data sharing requirements of Charging Forward (8T 3615).

The PFD also declined to recommend Staff's "future-proofing" proposal, noting that "in light of rapidly evolving EV technologies, it is difficult to determine what future proofing would entail" (PFD, p 188). To the extent "future-proofing" as defined by Staff is possible and reasonable, then the Company will do so. When the site host expresses interest in upgrading the equipment to higher-powered charging in the future (e.g., with Electrify America and Tesla), the Company will factor this into the make-ready infrastructure requirements. However, the Company does not agree that it is universally reasonable nor even possible to "future proof" every aspect of an emerging technology 8T 3615-16. See also DTE Electric Reply Brief, pp 142-43).

property to serve the public, and correspondingly receives a reasonable return on the value of its private property. In *Board of Public Utility Comm'rs v New York Telephone Co*, 271 US 23; 46 S Ct 363; 70 L Ed 808 (1926), the United States Supreme Court explained that the just compensation safeguarded to the utility by the Fourteenth Amendment is a reasonable return on the value of the property used at the time that the property is being used for the public service. Rates that are not sufficient to yield that present return are confiscatory. 271 US at 31. If the Commission were to order additional funding for Charging Forward expansion (or anything else), then that funding must be recovered though a corresponding rate increase.[44] [45]

5. The Company has already addressed the request to "file a rate that addresses the issue of demand charges" by offering its D3 General Services rate.

The PFD recommended a demand charge holiday, stating:

> DTE Electric's position on this issue is unpersuasive. As established by the record, during the initial stages of EV infrastructure development, demand charges pose a significant and unnecessary economic impediment to the successful deployment of publicly available DCDF charging stations. Further, the incongruity of DTE Electric's proposed D1.9 Experimental Electric Vehicle Rate, which has a demand charge, and DTE Electric's D3 General Service Rate, which does not have demand charge, is hard to reconcile. Therefore, based on the record presented, it is

[44] DTE Electric has constitutional protections against "takings" and confiscatory rates under the Fifth Amendment to the US Constitution, which is applicable to the states through the Fourteenth Amendment. Similarly, Const 1963, art 10, § 2 provides in part, "Private property shall not be taken for public use without just compensation therefore being first made or secured in a manner prescribed by law." These constitutional protections have been recognized and applied to public utility rates in well-established case law. *See generally, Missouri ex rel Southwestern Bell Telephone Co v Public Service Comm of Missouri*, 262 US 276; 43 S Ct 544; 67 L Ed 981 (1923); *Federal Power Comm v Natural Gas Pipeline*, 315 US 575; 62 S Ct 736; 86 L Ed 1037 (1942); *Duquesne Light Co v Barasch*, 488 US 299; 109 S Ct 609; 102 L Ed 2d 646 (1989). *See also, Northern Michigan Water Co v Public Service Comm*, 381 Mich 340; 161 NW2d 584 (1968); *Consumers Power Co v Public Service Comm*, 415 Mich 134; 327 NW2d 875 (1982); *ABATE v Public Service Comm*, 430 Mich 33; 420 NW2d 81 (1988).

[45] As a matter of fundamental ratemaking law, DTE Electric is entitled to a commensurate return of and on its investment in providing utility service. *See, Bluefield Waterworks Improvement Co v Public Service Commission of West Virginia*, 262 US 679, 690-694; 43 S Ct 675; 67 L Ed 1176 (1923); *Federal Power Comm v Hope Natural Gas Co*, 320 US 591, 603; 64 S Ct 281; 88 L Ed 333 (1944). *See also, Permian Basin Area Rate Cases*, 390 US 747, 769-70; 88 S Ct 1344; 20 L Ed 2d 312 (1968); *FPC v Memphis Light, Gas and Water Division*, 411 US 458; 43 S Ct 1723; 36 L Ed 2d 426 (1973); *General Telephone Co v Public Service Comm*, 341 Mich 620; 67 NW2d 882 (1954); *Michigan Consolidated Gas Co v Public Service Comm*, 389 Mich 624; 209 NW2d 210 (1973).

> recommended that the Commission adopt Staff's proposal for a demand charge holiday, for EV site hosts, to be offered by DTE Electric for up to five years. [PFD, p 198.]

The ALJ misunderstands DTE Electric's rate offerings. First, Rate Schedule D1.9 (available to both residential and commercial customers) does not have an associated demand as part of its rate structure (See Exhibit A-16, Schedule F10). Second, the Company's commercial customers can also choose additional rate products without demand rates: the D3 General Service Rate, and D3.3 Interruptible General Service Rate. The D3 General Service Rate is a commercial rate without demand charges (as Staff similarly noted at Initial Brief, p 130). However, it is up to the customer to decide what is the best rate structure option (8T 3624). Thus, the Company believes that the issue of a demand charge for site hosts in DTE Electric's service territory is moot and does not need to be addressed with any additional requirement. Finally, even if it were true that the Company's commercial rates only had options with demand rates (which it does not), adopting a "demand rate holiday" disregards the requirement for cost based ratemaking set forth in MCL 460.11 which provides, "[e]xcept as otherwise provided in this subsection, the commission shall ensure the establishment of electric rates equal to the cost of providing service to each customer class".

6. The PFD's DCFC charging recommendation should be clarified.

The PFD "recommends that the Commission direct DTE Electric to engage in the same consumer protection measures as were approved in the Consumer's settlement" in Case No. U-20134 (PFD, p 201). The Company agrees with the concept of reasonableness for DCFC charging and that it should work to ensure that the cost per charge is within market rates. The Company's reading of the Consumers' settlement is consistent with this viewpoint (See, for example, January 9, 2019 Order Approving Settlement Agreement in Case No. U-20134, Attachment A: "Educate site hosts about applicable electricity rates and EV benefits, while site hosts retain ability to set pricing that reflects on-site needs").

The Company takes exception seeking clarity because the PFD further stated that "MEC/NRDC/SC provides the most reasonable solution" (PFD, p 201), and the Company disagrees with MEC/NRDC/SC's suggestion that the Commission should establish a specific standard.[46] The Company has indicated that through a collaborative approach with site hosts it will be able to positively influence the reasonable delivery of EV charging services. The Company will educate site hosts on acceptable pricing structures and track the price site hosts "charge for charging" and will aim to identify any outliers and find ways to collaborate to address the situation (8T 3624). At this early stage in market development, the Company does not see the need to begin to impose specific standards, especially as there is no evidence that supports their imposition. Through its annual reports, the Company will provide updates to the Commission and to the extent it feels there is a need to impose a standard, it will propose one at that time.

F. Infrastructure Recovery Mechanism ("IRM").

DTE Electric proposes an Infrastructure Recovery Mechanism ("IRM") to recover the incremental revenue requirement associated with certain distribution, fossil generation and nuclear generation capital expenditures through 2022. The PFD instead agreed with the parties opposing the IRM, stating that "the IRM, as proposed by the company, is too expensive, too expansive, and allows the company too much discretion in spending before any review of reasonableness and prudence occurs . . . [and] the IRM could be rejected on policy grounds alone" (PFD, pp 217-18).

The Intervenor positions do not acknowledge the extensive prior proceedings establishing and expanding DTE Gas's very similar IRM, which began when the Commission approved DTE

[46] MEC/NRDC/SC suggested that "a reasonable standard for this purpose would be to limit the total cost per charging session at a rebated DCFC to roughly the cost of gasoline providing equivalent mileage" (Initial Brief, p 87, quoting Mr. Jester at 6T 2217-18).

Gas's recovery of 2013-17 IRM capital investments for its the Meter Move Out Program ("MMO"),[47] the Main Renewal Program ("MRP"),[48] incremental MRP, and Pipeline Integrity ("PI") investments. (April 16, 2016 Order in Case No. U-16999). The Court of Appeals affirmed each of these investment mechanisms. *In re Application of Michigan Consolidated Gas Company to increase rates*, unpublished opinion per curiam of the Court of Appeals, issued December 11, 2014 (Docket Nos. 316141 and 316263) (2014 WL 7003882). The Commission approved additional infrastructure investments as part of an expanded IRM for 2016 and 2017 (November 23, 2015 Opinion and Order in Case No. U-17701). The Commission authorized spending of $102.1 million in 2016, and $127.6 million in 2017 through 2021 on IRM programs, as well as flexibility in spending among the programs (December 9, 2016 Order in Case No. U-17999, pp 52, 67). Most recently, the Commission approved additional capital expenditures, including funding to expand and accelerate infrastructure replacement (September 13, 2018 Order in Case No. U-18999, pp 21, 26, 32-33).

The Commission has also approved various cost recovery trackers, and the Court of Appeals has consistently affirmed them. In addition to DTE Gas's IRM, see, for example, *In re Application of Detroit Edison Company*, 296 Mich App 101, 114; 817 NW2d 630 (2012), where the Court of Appeals affirmed four cost trackers for DTE Electric in Case No. U-15768 (an Uncollectible Expense Tracking Mechanism ("UETM"), a storm and non-storm restoration normalization tracker, line clearance expenses tracker, and Choice Incentive Mechanism ("CIM")). The Court explained in part that "our case law confirms that the PSC correctly approved

[47] The Commission approved the MMO in its September 13, 2011 Opinion and Order and November 10, 2011 Order Granting Clarification in Case No. U-16451.

[48] The Commission approved the MRP in its September 13, 2011 Order in Case No. U-16407.

Detroit Edison's use of cost tracking mechanisms through which future rates are adjusted to take account of actual past expenses."

DTE Electric's proposed IRM is also appropriate because the Company's need for rate increases has been, and is expected to continue to be, largely driven by its need to replace critical infrastructure that is required to safely and reliably serve its customers. The Company believes that the proposed IRM may enable it to defer filing for a rate increase until sometime in 2022 for new base rates in 2023 (3T 75).[49] The proposed IRM should therefore reduce resources and costs for all parties that typically participate in Company rate cases. The systematic implementation of IRM surcharges should also benefit customers by allowing for more orderly and potentially smaller rate cases than what would occur if the Company continued to file annual rate cases. The IRM would support critical infrastructure improvements that will benefit customers for years to come and should also facilitate the more efficient deployment of capital by providing a level of certainty for cost recovery (3T 74-75).

The PFD's criticisms of the IRM are also unsupported by the record, which reflects that the Company seeks IRM treatment for capital expenditures that are above and beyond replacement capital (normal capital expenditures that are effectively replacing capital that is being depreciated). The proposed IRM would cover these capital expenditures beginning May 1, 2020 (the first day

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[49] DTE Electric cannot guarantee that it will be able to defer filing a rate case until 2022 since the Company faces many cost pressures and uncertainties beyond the capital expenditures that would be covered by the IRM. These include incremental capital expenditures that are not included in the IRM, O&M general inflation or other O&M cost increases, reductions in sales, and any other unforeseen external events, such as new energy legislation. Using a relatively predictable cost increase of inflation for example, the Company's proposed O&M for the projected test year is $1.3 billion. Since O&M is not included in the IRM, even if the Company experiences general inflation of just 2% per year, it will have to absorb about $26 million of increased costs annually (3T 75-77).

Although there are several cost and revenue areas, beyond the capital expenditures covered by the proposed IRM, that could make it difficult for the Company to defer filing a rate case until 2022, the Company believes that with the proper IRM in place, it may be able to defer filing for a rate increase until sometime in 2022 for new base rates in 2023 (3T 105).

after the projected test year) through December 31, 2022. Like DTE Gas's IRM (see, for example, December 9, 2016 Order in Case No. U-17999, pp 47-48), capital expenditures used to calculate the IRM surcharge are made on a calendar year basis. The initial IRM surcharge would be implemented January 1, 2020, and cover capital expenditures from May 1, 2020 through December 31, 2020. Similarly, incremental IRM surcharges would be implemented January 1, 2021 and 2022 for the IRM capital expenditures for the 2021 and 2022 calendar years (3T 77-78; 5T 1515). Exhibit A-30, Schedule T1 summarizes the capital expenditures included in the IRM (7T 3337).

Mr. Bruzzano supported Distribution Operations ("DO") capital expenditures that the Company proposes to include in the IRM (4T 809; Exhibit A-30, Schedule T2). He explained that he selected DO programs and projects to include in the IRM because they are either required[50] or have a high degree of certainty in being executed due to their priority in terms of their ability to reduce risk, improve reliability, and manage costs (4T 801-803). The Company proposes to include Strategic Capital projects from the Five-Year Plan as shown on Table 22 at 4T 804 and further described in Exhibit A-30, Schedule T2.1, which contains a description of the drivers, scope, and customer benefits for the projects and programs. Table 23 on 4T 806 provides some additional, directional information on the scope of some of the programs. The Company will also provide additional information (in the fall annual plan review with Staff, further discussed below) as detailed engineering, design and procurement activities are completed (4T 803-806, 811).

[50] IRM Base capital expenditures include emergent replacements that are necessary to restore service to customers and return equipment to proper working condition, as well as certain types of new business connections, relocations, and equipment purchases that directly benefit customers and for which there is a high degree of confidence in the conservatively-set spending level. Exhibit A-30, Schedule T2, page 1, lines 2-4 shows capital expenditures for emergent replacements, with the details on page 2. Exhibit A-30, Schedule T2, page 1, line 5 shows capital expenditures for Small Growth Load Projects, Customer Connections, Small Relocations, and Electric System Equipment purchases, with the details on page 3 (4T 801-03, 809-10). The same format continues through the exhibit (4T 810-11).

Mr. Paul supported Fossil Generation capital expenditures that the Company proposes to include in the IRM for planned and scheduled work needed to ensure continued safe and reliable operations at the Company's Tier 1 generating units (Monroe, Belle River, and Greenwood) and peaker units, along with capital expenditures related to the construction of the 1,100 combined cycle gas turbine ("CCGT") plant that was approved in Case No. U-18419 (4T 587; Exhibit A-30, Schedule T3). Fossil generation proposes that a portion of expenditures relating to the following four categories be recovered through the IRM: (1) planned outage work on Tier 1 steam generating units (explained and supported at 4T 588 and shown on line 1 of Exhibit A-30, Schedule T3); (2) scheduled capital equipment replacements on Tier 1 steam generating units (explained and supported at 4T 589 and shown on line 2 of Exhibit A-30, Schedule T3); (3) planned outage work on large gas-fired peakers (explained and supported at 4T 589-90 and shown on line 3 of Exhibit A-30, Schedule T3); and (4) costs to build the new CCGT plant (explained and supported at 4T 590 and shown on line 4 of Exhibit A-30, Schedule T30).

Mr. Davis supported Nuclear Generation capital expenditures that the Company proposes to include in the IRM (5T 1296; Exhibit A-30, Schedule T4). Including Nuclear Generation in the IRM will allow recovery of capital expenditures required to maintain Fermi 2's current level of safe and reliable operations beyond the projected test year. Nuclear generation proposes to include two programs in the IRM: (1) Routine and Small Projects, and (2) Non-Routine and Large Projects. These two consistently-used programs best align how Nuclear Generation approaches its work, especially in the context of a refueling outage (5T 1297-98). Non-Routine and Large Projects are associated with large capital projects that Nuclear Generation expects to implement only once through Fermi 2's current operating license expiration in 2045 (5T 1298). Mr. Davis further discussed the (1) fire header restoration and (2) Emergency Diesel Generator ("EDG") control

relay projects as examples (5T 1298-1300). Routine and Small Projects are projects that Nuclear Generation expects to implement two or more times throughout Fermi 2's remaining life. Many of these projects are implemented every operating cycle. Mr. Davis further discussed the (1) control rod blades and (2) snubbers projects as examples (5T 1301-1302).

Exhibit A-30, Schedule T5, page 1 identifies the annual incremental revenue requirements for 2020 through 2022 relating to DO capital costs (5T 1514-15). Similarly, Exhibit A-30, Schedule T6, page 1 identifies the annual incremental revenue requirements relating to Generation capital costs discussed by Mr. Paul and Mr. Davis (5T 1516), and Exhibit A-30, Schedule T7, page 1 identifies the annual revenue requirements relating to the new CCGT plant (5T 1517-18). Mr. Slater also explained how he calculated amounts for the six months ending April 20, 2020 in these categories for inclusion in the IRM (5T 1515, 1517-18).

DTE Electric proposes some flexibility in spending, but does not seek to move any capital between the three broad business units of distribution, generation, and CCGT plant. Within those business units, however, the Company proposes to be able to move up to 20% of the capital dollars to or from any discrete category of work as defined on Exhibit A-30, Schedules T2, T3, and T4 (3T 81; 4T 806-807).[51]

The cost of service methodology relative to IRM rate base will follow the same cost of service methodology as other similar capital that is reflected in base rates (3T 79-80). Exhibit A-

[51] For example, flexibility is needed regarding DO spending because even though the Company has a clear prioritization of projects and programs that it intends to execute, there is inherent complexity and uncertainty that can affect actual timing and spending due to delays in obtaining easements and permits, unplanned equipment failures or adverse weather. The Company similarly needs the ability to switch the order of projects within each category if required by operational or other circumstances (4T 806-807).

Nuclear Generation similarly needs flexibility because nuclear safety is the overriding priority and changes in plant conditions and regulatory requirements necessitate some funding reallocation. For example, Fermi 2 must remain in compliance with all NRC regulations. Following the 2011 events at the Fukushima Dai-ichi nuclear plant, the NRC issued new regulations necessitating billions in industry capital expenditures and U.S. nuclear plants had only four years to comply (5T 1303).

30, Schedule T8 reflects the allocation of the production-related IRM revenue requirement to the various rate classes. Exhibit A-30, Schedule T9 reflects the allocation of the distribution-related revenue requirement to the various voltages (7T 3225-26). Any revised IRM revenue requirements resulting from an IRM reconciliation (discussed further below) would be allocated to the various rate and voltage classes in the same way (7T 3226-27).

The Company's proposed IRM power supply and delivery surcharges are designed to collect the above-described revenue requirements by class (5T 1221, 1240-41; Exhibit A-30, Schedule T10). The Company proposes a per kWh charge for residential and small commercial customers, and an IRM demand charge for large commercial and industrial customers on rate schedules with a demand component (3T 80; 5T 1241). The Company proposes to record revenue on an accrual basis consistent with its accounting for other customer revenues. The capital expenditures will be recorded to unique accounting codes to isolate the costs (7T 3338).

The Company proposes to reconcile the IRM surcharge such that if the Company under spends the capital reflected in the IRM surcharge, it will refund the IRM revenue associated with that under spending. However, there would not be any additional surcharge if the Company over spends beyond the level approved in the IRM. The Company also proposes to reconcile the revenue collected through the IRM so that if the Company over or under recovers what it should recover under the IRM, then the Company will refund or surcharge that difference at the conclusion of the IRM. In no event, however, would the Company be allowed to recover more than the maximum amount of revenue defined by the IRM. Thus, if the Company under spends capital, then the total amount of revenue that the Company can recover will be reduced based on that under spend. In summary, there would be an asymmetrical reconciliation for capital spending (refund underspending; no recovery for overspending), and a symmetrical reconciliation for revenue

recovery up to the maximum allowed revenue based on the operation of the IRM (3T 78; 5T 1242, 1520). Mr. Slater also prepared an illustrative example (5T 1520-21; Exhibit A-30, Schedule T13).[52]

The Company further proposes that any over or under recovery be deferred as a regulatory liability or regulatory asset until the next IRM reconciliation. Once the IRM is terminated, there would be one final reconciliation that would include all net amounts over the period (plus any applicable interest) and result in a refund or surcharge. This is essentially the same over or under recovery reconciliation methodology that is already in use for the Company's Transition Reconciliation Mechanism ("TRM") for the transition of Detroit Public Lighting Department ("PLD") customers to DTE Electric service. Short-term interest should be accrued on any over or under recovery. The Company proposes to file the initial reconciliation by April 30, 2021 for capital expenditures from May 1, 2020 through December 31, 2020. Similar reconciliations would be filed by April 30 of the subsequent years for 2021 and 2022. The IRM surcharge would expire when new base rates are set by Commission order in the Company's next general rate case (3T 79; 5T 1242; 7T 3338).

Finally, DTE Electric proposes to report on IRM work to ensure that that capital approved in the IRM is not only spent, but also spent efficiently and effectively. The Company specifically proposes to (1) meet with the Staff each fall to review expected IRM expenditures and the scope of IRM work to be accomplished for the upcoming IRM year, (2) provide Staff with a summary

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[52] ABATE suggested that the proposed IRM is an unlawful "automatic adjustment clause" under MCL 460.6a(4). (ABATE Initial Brief, pp 43-44, quoting the statute in relevant part: "The commission shall not authorize or approve adjustment clauses that operate without notice and an opportunity for a full and complete hearing, and all such clauses are abolished"). The Commission and Court of Appeals rejected this same argument (the statutory language was then in MCL 460.6a(2)) in establishing and affirming DTE Gas's IRM. *In re Application of Michigan Consolidated Gas Company to increase rates, supra*, 2014 WL 7003882 at *2 and *4-5 (explaining that the "full and complete hearing" requirement is satisfied by limited annual reconciliation proceedings).

of actual work completed (Program Metrics)[53] in each reconciliation, (3) report performance indicators to the Staff annually,[54] and (4) meet with the Staff throughout the year to review progress relative to the plan (3T 80-81; 4T 590-91, 807-808; 5T 1300, 1302, 1304-05). The Company also proposes to file a report with the Commission regarding the expenditures and metrics for the period May to December 2020 by April 30, 2021. Annual reports for 2021 and 2022 would similarly be filed by April 30 of the following year (7T 3337-38).

In summary, IRMs are well established in law and regulatory practice, and the Company's proposed IRM is well designed and fully supported. Therefore, it should be approved along with the Company's proposed IRM power supply and delivery surcharges included in Exhibit A-30, Schedule T10.

G. The nuclear surcharge should be increased, but the PDF's recommendation for an updated decommissioning cost study should be rejected.

DTE Electric proposed to increase the nuclear surcharge due to increased Site Security and Radiation Protection ("SSRP") costs and low level radioactive waste ("LLRW") disposal funding,

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[53] DO Program Metrics are shown on Table 24 at 4T 808.

For Fossil Generation, Mr. Paul suggested specific program metrics relating to each of the four categories of capital spending discussed above and shown on Exhibit A-30, Schedule T3, lines 1-4 (4T 591-92). For Nuclear Generation, Mr. Davis proposed the "number of projects complete" as the metric for Non-Routine and Large Projects (5T 1300), and "number of units complete" as the metric for Routine and Small Projects (5T 1302).

[54] Regarding DO, the Company will provide the Staff with a yearly report on the average age and age risk for key asset classes (breakers, switchgear, etc.) along with the risk assessments for priority asset classes, so the extent to which aging and at-risk equipment is being replaced can be evaluated. The Company will also report the operational performance indicators listed in Table 25 at 4T 809 (4T 808-809). Fossil Generation will provide a report to the staff on unplanned unit outages that have occurred due to failures on components replaced within IRM projects completed in the preceding year (4T 592). For Nuclear Generation, Mr. Davis proposed a performance indicator called "Total Number of Unplanned Power Losses per 7,000 Critical Hours" (for brevity, "Unplanned Power Change Events"). This is an industry metric that measures organizational effectiveness by counting the number of unplanned automatic and manual scrams (reactor shutdowns) and the number of unplanned power changes in reactor power greater than 20% of full power per 7,000 hours of operation (5T 1304-1305).

and lower forecasted jurisdictional sales (5T 1227).[55] Staff calculated the proposed nuclear surcharge in the same manner as the Company did, and agreed with the Company's proposed nuclear surcharge increase (8T 4286). ABATE proposed that the Commission should instead set the nuclear surcharge revenue requirement at $27.482 million (a $10.8 million reduction from DTE Electric's proposal) by eliminating LLRW funding ($6 million) and the Nuclear Decommissioning funding ($2.9 million) and reducing SSRP funding ($1.9 million). The PFD stated:

> This PFD finds that DTE Electric's nuclear surcharge should be approved as proposed, subject to a requirement that the company provide an updated decommissioning study in its next rate case, or in a stand-alone proceeding as has been done in the past. DTE Electric correctly pointed out that the amounts in the nuclear trust fund cannot be reallocated without NRC approval. However, ABATE presented compelling evidence that the assumptions underlying the calculation of the amount needed to decommission Fermi 2 may no longer be valid and should be revisited. DTE Electric did not dispute that the last decommissioning study was performed years ago, nor did it rebut Mr. Andrew's evidence about decommissioning amounts in trust funds for other nuclear plants that are roughly 50% of the amount DTE Electric has in its trust fund on a cost per kW basis. [PFD, p 221. Footnote omitted.]

The PFD approved DTE Electric's nuclear surcharge proposal; however, it was improper to recommend that the approval be "subject to a requirement" for the future. *Detroit Edison Co v Public Service Comm*, 264 Mich App 462, 467; 691 NW2d 61 (2005) (MPSC could not "approve" a utility's recovery of costs and later attempt to eradicate that approval based on subsequent events).

DTE Electric also disagrees that an updated decommissioning study is either necessary or appropriate. Company witness Mr. Davis explained that Fermi 2 is licensed to operate through

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[55] The nuclear surcharge recovers costs associated with nuclear site security and radiation protection, the funding for nuclear decommissioning, and LLRW disposal. These activities are required for Fermi 2's safe and secure operation. The Company requests a nuclear surcharge increase primarily for increased LLRW disposal funding (a $2 million increase from $4 million to $6 million), which is reasonable and prudent to minimize the accumulation of LLRW at Fermi 2, and dispose of LLRW in a timely and proper manner. There are also inflationary increases to site security and radiation protection costs. The resulting nuclear surcharge is $38.3 million for the projected test period (5T 1293-96, 1309; Exhibit A-20, Schedule J1, page 1, line 6, column (b); Exhibit A-16, Schedule F6).

2045 (5T 1270). The Fermi 2 decommissioning cost estimate complies with NRC regulations, and satisfies its intended purpose to provide reasonable assurance knowing that more exact estimates are timed closer to actual decommissioning. It is also reasonable and complete considering what is presently known. The cost estimate is consistent with the regulatory guidance, and the assumptions underlying that cost estimate are well documented and sound. The assumptions encompass radiological decommissioning of the plant, as well as post-shutdown fuel stewardship and greenfielding costs. The cost estimate also accounts for taxes, insurance, NRC fees and hazardous waste fees (5T 1320-21).

The Fermi 2 decommissioning cost estimate remains reasonable and prudent, and has more than a decade of Commission oversight supporting its central assumptions. The PFD's proposal would require DTE Electric to divert time and resources and unnecessarily incur costs to produce a Fermi 2 decommissioning cost estimate that will still be many years in advance of the projected cessation of Fermi 2's operations (5T 1326-27).

The PFD's suggestion that DTE Electric may be over-recovering decommissioning funds also disregards DTE Electric's prior requests to lower the Nuclear Decommissioning funding when reasonable analysis concluded that it was prudent to do so, with resulting decreases of approximately \$30 million in annual requirements since 2011 (5T 1319-22).[56] Moreover, the nuclear utility industry is one of the most highly monitored and regulated industries in the country. All aspects of site security and radiation protection are scrutinized on a regular basis. DTE Electric also provides cost and other regulatory information to the Commission, including the 2018

[56] As requested by the Company, the Commission lowered the Nuclear Decommissioning funding from approximately \$33 million to approximately \$13 million in Case No. U-16472, and from there to the current \$2.9 million in Case No. U-17767. The Commission re-authorized the \$2.9 million in Case Nos. U-18014 and U-18255 (5T 1322).

triennial report (Exhibit AB-7).[57] DTE Electric should not be burdened with yet another requirement that would provide no benefit (5T 1327-28).

Therefore, DTE Electric's proposed nuclear surcharge should be approved, but the PFD's further recommendation to require the Company to provide an updated decommissioning study should be rejected.

VI. THE COMMISSION SHOULD ADOPT DTE ELECTRIC'S COST ALLOCATION AND RATE DESIGN PROPOSALS.

A. There is no valid basis to revisit production cost allocation.

MEC/NRDC/SC witness Mr. Jester asserted that the Company allocates too much of its production costs on contribution to peak (4CP) and too little on energy, and proposed that the Commission should require that costs allocated to capacity (production) be limited to the Cost of New Entry ("CONE") adjusted for planning reserve margin with the remainder allocated to energy (6T 2187-92). Mr. Lacey responded that Mr. Jester's proposal boils down to a disagreement with the 4CP 75-0-25 method for production allocation that the Commission adopted in Case No. U-17689 (in accordance with 2014 PA 169) and has continuously applied in subsequent DTE Electric rate cases, Case Nos. U-17767, U-18014, and U-18255. There is no basis to now reconsider or deviate from that methodology (7T 3234).

MEC/NRDC/SC acknowledged: "Certainly no one could fault Mr. Lacey for allocating production costs in his COSS consistent with recent precedent" (MEC/NRDC/SC Initial Brief, p 142). Regardless, they asserted that the Commission should modify production cost allocation or revisit the issue in the next rate case (*Id*, pp 138-44). The PFD agreed, recommending "that

[57] DTE Electric submits a report to the Commission every three years, the latest of which was January 31, 2018 (5T 1323).

production cost allocation should be revisited in either the company's next rate case, or in a special purpose proceeding as was done in Case No. U-17689" (PFD, p 228).

DTE Electric disagrees. In addition to Mr. Lacey's testimony, noted above, there is no valid reason for the Commission to contemplate revisiting the issue. Although *res judicata* and collateral estoppel do not apply "in a strict sense" to the Commission's ratemaking decisions, "issues fully decided in earlier PSC proceedings need not be 'completely relitigated' in later proceedings unless the party wishing to do so establishes by new evidence or a showing of changed circumstances that the earlier result is unreasonable." *Application of Detroit Edison to Implement Opt-Out Program*, unpublished opinion per curiam of the Court of Appeals, issued February 19, 2015 (Docket Nos. 316728 and 316781), *lv den* 499 Mich 868 (2016), *reh den* 499 Mich 972 (2016). (Opinion affirming AMI opt-out charges, p 8, citing *Application of Consumers Energy Co*, 291 Mich App 106, 122; 804 NW2d 574 (2010), which quoted *Pennwalt Corp v Public Service Comm*, 166 Mich App 1; 420 NW2d 156 (1988)).

More recently, in response to RCG argument that the opt-out charges should be reduced to zero, the Court of Appeals explained:

> In this appeal, [RCG] again argues that the opt-out charges should be eliminated. [RCG] first contends that there was no evidence presented in the current proceeding supporting the amount of the fees. The reason for this was simple: DTE was not seeking to alter the opt-out fees, which had been set in Case No. U-17053. As the MPSC has explained previously, there is no need for the MPSC to take new evidence on an issue that has been decided previously, absent a showing that circumstances have somehow changed. [*Application of DTE Electric Company to Increase Rates*, unpublished opinion per curiam of the Court of Appeals, issued October 25, 2018 (Docket No. 338378), reh den December 27, 2018, following *In re Consumers Energy Co App*, 322 Mich App 480, 493-94; 913 NW2d 406 (2017) and *Pennwalt Corp, supra*, 166 Mich App at 9.]

DTE Electric further objects to the extent that the PFD suggests that the Company has some burden to present an initial case, or otherwise re-prove the status quo. In addition to the discussion

above, see *Kar v Hogan*, 399 Mich 529, 539; 251 NW2d 77 (1976), where our Supreme Court explained that "[t]he party alleging a fact to be true should suffer the consequences of a failure to prove the truth of that allegation." Moreover, there is a heightened evidentiary presentation required for "any party proposing to revise the production cost allocation method in a future case" (January 31, 2017 Order in Case No. U-18014, pp 100-101).

B. DTE Electric's proposed capacity charge revenue requirement should be approved.

The November 21, 2017 Order in Case No. U-18248 (the Company's capacity charge case) approved the Company's method,[58] but adjusted for Gross Energy Sales net of fuel, and not the Company's recommended Net Energy Sales net of fuel costs. In Case No. U-18255, DTE Electric maintained its position from Case No. U-18248, but did not oppose Staff's suggestion to maintain the status quo in that case only. The Commission agreed with DTE Electric and Staff that the capacity charge had to be updated, and approved Staff's proposal regarding gross energy sales net of fuel costs (April 18, 2018 Order in Case No. U-18255, pp 62-63).

Here, Mr. Lacey calculated and explained the Company's capacity revenue requirement, which is reflected on Exhibit A-16, Schedule F1.5. The capacity revenue requirement includes all production-related costs per Exhibit A-16, Schedule F1.1, except fuel, variable O&M and certain purchase power costs. This is the same methodology that the Company supported in Case No. U-18255. As indicated above, the Commission's April 18, 2018 Order generally adopted this

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[58] "The Commission finds DTE Electric's proposed method, which begins with total embedded production related costs and subtracts the non-capacity related costs of fuel expense, variable O&M expense, and non-capacity related purchased power expense to be a reasonable method under Section 6w(3)(a)." (November 21, 2017 Order in Case No. U-18248, p 65).

approach, with the only differences being the amounts to be subtracted and the calculation of 2018 energy sales net of fuel on line 2 of Exhibit A-16, Schedule F1.5 (3T 71-72; 7T 3221-22).

As indicated above, the Commission's April 18, 2018 Order in Case No. U-18255 reflected a $584 million reduction for energy sales net of fuel, based on a calculation originally adopted in Case No. U-18248. Here, Mr. Lacey used the $40.3 million calculation of energy sales net of fuel supported by Mr. Arnold on Exhibit A-29, Schedule S3 (7T 3222).[59] Mr. Lacey also explained line items in Exhibit A-16, Schedule F1.5, and supported the resulting $1,947 million total capacity charge revenue requirement (7T 3222-25).

The PFD instead agreed with Staff, ABATE, Energy Michigan, and Kroger that the Commission should maintain the capacity cost allocation method from Case Nos. U-18248 and U-18255 (PFD, p 232). DTE Electric disagrees. As explained by Company Witnesses Arnold (3T 288-293) and Stanczak, (3T 70-73), the Company's calculation of $40.3 million of energy sales net of fuel is consistent with PA 341 Section 6w (3)(B) and results in Electric Choice customers paying the same full embedded cost of DTE Electric's electric generation fleet as bundled customers. Thus, the Company's position should be adopted.

The PFD further recommended adopting the Staff's approach to recalculating and updating the capacity charge, which appears to contemplate that the final order in this case would produce a capacity charge incorporating updated costs from this case (PFD, p 233). The Company notes that generally, any base rate or PSCR factor change will change the capacity charge rates. The

[59] Mr. Arnold explained the capacity-related generation costs (PURPA power purchase agreements, PA 295 Company-owned renewable energy systems, PA 295 renewable energy contracts, and capacity purchases) included in the Company's PSCR factor as required by MCL 460.6w(3)(A) (3T 288-90; Exhibit A-29, Schedules S1 and S2). He also explained the projected 2018 energy sales revenue net of projected fuel costs per MCL 460.6w(3)(B) (3T 290-93; Exhibit A-29, Schedule S3). He concluded: "The total projected 2018 energy sales revenue of $89.7 million, net of 449.2 million in fuel related costs and $0.2 million in Schedule 17 admin fees equates to $40.3 million energy sales revenue net of fuel related costs as shown on Exhibit A-29, Schedule S3, line 32" (3T 293).

Commission must also conduct a capacity charge review by December 1 of each year. MCL 460.6w(3). The Company proposes that the capacity charge rates established by the Commission pursuant to the December 1 review become effective on January 1 of the following year. There are costs and revenues in the capacity charge and the PSCR that are directly related. The PSCR operates on a calendar year basis, so administrative efficiency would be achieved by reflecting PSCR changes in the capacity charge on a calendar year basis and then reconciling them contemporaneously for that same calendar year (3T 72-73).

In light of the above, DTE Electric requests that the Commission adopt the methodology proposed by the Company for calculating and applying the Capacity Charge Revenue Requirement.

C. DTE Electric's residential and commercial secondary monthly service charges should be adopted.

The Company's cost allocation resulted in customer-related costs by rate class of $45.53 for residential, and $178.88 for commercial secondary (7T 3221; Exhibit A-16, Schedule F1.4).[60] Based on Mr. Lacey's analysis of customer related costs, the Company could have proposed moving to higher monthly service charges for both residential and commercial secondary customers, but in the interest of gradualism, DTE Electric proposes to change the monthly service charge to $9.00 per customer for residential rate schedules that are not for supplemental electric service (D1, D1.2, D1.6, D1.8, and D2, but not D1.1, D1.7, D1.9 and D5), and to increase the

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[60] These customer-related costs were determined using all fixed distribution costs (demand plus customer), in accordance with the National Association of Regulatory Utility Commissioners ("NARUC") Electric Utility Cost Allocation Manual (Exhibit A-39, Schedule CC-1), which classifies both distribution plant and equipment as demand-related, customer-related, or a combination of those two (and not energy related). Demand-related costs are fixed costs. Cost causation should match cost recovery as much as possible. Residential and small commercial rates do not include a demand charge, so the customer charge must be used to collect the demand-related fixed costs. Therefore, all fixed costs, demand and customer related, should be recovered through the fixed customer charge (7T 3219-21).

monthly service charge to $15 per customer for commercial secondary rate schedules that are not for supplemental electric service (D1.8, D3, D3.2, D3.3, D4, and R8 separately metered).

The PFD instead found that Staff's recommendation to maintain the current charges should be adopted and criticized DTE Electric for again presenting a cost-allocation methodology that the Commission has not accepted (PFD, p 235). The Company maintains that its methodology is appropriate and notes that much of the opposition was based on the faulty premise that there would be a residential rate increase. However, if the service charge does not increase, then the variable distribution rate must be higher than what is proposed so that the Company's distribution rates will recover the same amount of revenue. The Commission has previously recognized that such a fixed-charge increase "does not increase the residential class' cost of service. Rather, it merely reflects the fact that a flat customer charge, rather than an energy related charge, is a more appropriate way of collecting the fixed costs associated with serving each residential customer at any usage level" (8T 3869; June 10, 2008 Order in Case No. U-15245, p 74).

Most of the revenue collected from residential customers would continue to come from rates dependent on usage. For a 600 kWh per month D1 customer, the Company's proposal to increase the service charge to $9.00 would increase the proportion of the bill due to fixed charges from 8% to 9%, so 91% of the bill would still be due to variable charges. For a 300 kWh per month D1 customer, the Company's proposal to increase the service charge to $9.00 would increase the proportion of the bill due to fixed charges from 15% to 17%, so 83% of the bill would still be due to variable charges. Thus, for the examples provided, Exhibit A-16, Schedule F7 shows that a D1 customer's bill is still significantly driven by variable versus fixed charges (8T 3870-71). Exhibit A-16, Schedule F7 also shows that the proportion of customers' bills due to fixed costs with the proposed $9.00 charge are very close to the proportions that existed when the service

charge was initially established at $6.00 in Case No. U-15244 (8T 3870-71). In addition, Exhibit A-16, Schedule F3, page 2 shows revenue from kWh-based charges account for over 90% of the total D1 revenue, under both present and proposed rates (8T 3871).

Similarly, most of the revenue collected from commercial secondary customers would continue to come from rates dependent on usage. For a 1,600 kWh per month customer, the Company's proposal to increase the service charge from $11.25 to $15.00 would increase the proportion of the bill due to fixed charges from 5.6% to 7.2%, so over 90% of the bill would still be due to variable charges. For a 3,200 kWh per month customer, the Company's proposal to increase the service charge from $11.25 to $15.00 would increase the proportion of the bill due to fixed charges from 2.9% to 3.7%, so over 95% of the bill would still be due to variable charges. The effect on larger customers would be even smaller. The proposed $15.00 service charge would not significantly affect energy efficiency decisions because customer bills would remain driven by variable charges (5T 1430-32).

To address concerns with low-income customers, the Company has also proposed to increase the Residential Income Assistance ("RIA") Service Provision of the D1 tariff. The RIA provision currently provides a $7.50 per month credit for qualifying customers, which offsets the current $7.50 monthly service charge. DTE Electric proposes to increase the credit to $9.00 per customer per month, so that the credit would continue to fully offset the monthly service charge (8T 3868-69). The Company also proposes to increase the Residential Senior Service Provision of the D1 tariff. This provision currently provides a $3.75 per month credit for qualifying customers, which offsets half of the current $7.50 monthly service charge. DTE Electric proposes to increase the credit to $4.50 per customer per month, so that it would continue to offset half of the monthly service charge (8T 3869).

D. DTE Electric's primary service charge should be maintained.

DTE Electric does not propose to change the $275 monthly service charge for primary customers. Kroger asserted that this charge is not cost based, and that the Commission should instead adopt the $53.52 charge that Kroger supported in Case No. U-18255 (Kroger Initial Brief, pp 1-5). The PFD agreed, stating:

> This PFD finds that Kroger's position has merit, and that the customer charge for primary customers in this case should be calculated using the same method that the Commission has consistently approved for residential and commercial secondary customers. Mr. Bieber's proposal to use the cost-of-service based calculation from Case No. U-18255 is also reasonable and should be adopted. Alternatively, the Commission should direct DTE Electric, in its next rate case, to calculate the customer charge for primary customers consistent with the method used for residential and commercial secondary customers discussed above. [PFD, p 237.]

DTE Electric disagrees because there is no basis for the PFD's recommendation. Even Kroger witness Mr. Bieber acknowledged that the Commission rejected using the "Staff method" to calculate the primary service charge (7T 2713-14). Mr. Lacey testified that there is no merit in Mr. Bieber's reasoning that just because the Commission did not expressly say the charge is cost-based, that means it must not be. The Commission found the $275 charge to be reasonable in Case Nos. U-17767, U-18014, and U-18255, and neither the Commission nor the Staff have ever advocated for using the "Staff method" for anything other than calculating residential and commercial secondary classes in those cases or this one (7T 3230-31; See also 8T 4268).

Additionally, Kroger's proposal relies on the record from Case No. U-18255 rather than the record in this case. [61] Kroger's proposal that the Commission alter its U-18255 decision based on the U-18255 record is essentially a request for rehearing of Case No. U-18255, which fails as

[61] The Commission's findings are required to be supported by record evidence. Const 1963, Art 6, § 28; MCL 24.276.

untimely under Rule 437(1) of the Commission's Rules of Practice and Procedure, R 792.10437(1). The Commission cannot lawfully deviate from its own rules.[62]

Kroger also does not offer anything that the Commission has not already considered. Although *res judicata* and *collateral estoppel* do not apply "in a strict sense" to the Commission's ratemaking decisions, "issues fully decided in earlier PSC proceedings need not be 'completely relitigated' in later proceedings unless the party wishing to do so establishes by new evidence or a showing of changed circumstances that the earlier result is unreasonable." *In re Application of Detroit Edison to implement opt-out program*, unpublished opinion of the Court of Appeals, issued February 19, 2015 (Docket Nos. 316728 and 316781), *lv den* 499 Mich 868 (2016), *reh den* 499 Mich 972 (2016) (2015 WL 728383 at * 6), citing *In re Application of Consumers Energy Co*, 291 Mich App 106, 122; 804 NW2d 574 (2010), and *Pennwalt v Public Service Comm*, 166 Mich App 1; 420 NW2d 156 (1988). Therefore, the $275 monthly service charge for primary customers from Case Nos. U-17767, U-18014 and U-18255 should be continued.

E. DTE Electric's Weekend Flex and Fixed Bill Pilots should be approved.

DTE Electric proposes to adopt a new Weekend Flex pilot and Fixed Bill pilot to address customer affordability and satisfaction. The PFD instead recommends that the pilots be rejected, or that the Commission modify them if they are adopted (PFD, pp 246-48). The Company disagrees that the pilots should be rejected.

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[62] *Complaint of Consumers Energy Co*, 255 Mich App 496, 501; 660 NW2d 785 (2002). *See also, DeBeaussaert v Shelby Twp*, 122 Mich App 128, 130; 333 NW2d 22 (1982) ("Once an agency has issued rules and regulations to govern its activity, it may not violate them"); *Bohannen v Sheridan-Cadillac Hotel, Inc*, 3 Mich App 81, 82; 141 NW2d 722 (1966) ("When an administrative agency promulgates a rule for the benefit of litigants and then deprives a litigant of this right, it is a violation of both the 1908 and 1963 Michigan Constitutions").

1. The Fixed Bill pilot should be adopted.

The PFD found "that the proposed Fixed Bill pilot program should be rejected on grounds that, more likely than not, the effects of the program would be contrary to the energy conservation goals of the State [of] Michigan and the company's energy efficiency efforts" (PFD, p 246). The intent of the Fixed Bill pilot was to design a new customer centric billing option through which DTE Electric customers can take electric service. As this is a voluntary program, it provides a compelling response to customer preferences outlined in the supporting consumer research. DTE Electric is not alone in expanding its tariff options for customers. Other U.S. utilities are currently offering successful Fixed Bill programs, one of which is Georgia Power with over 236,000 customers enrolled or 11% of its 2.2 million residential customers (6T 2102). While EWR is an important consideration, it is not the only consideration when designing a product or service that addresses customer requirements and the Company has carefully designed EWR elements into the program. Customer preferences in this case should be provided an equal, if not greater consideration in supporting this pilot. Even so, the PFD's concerns regarding EWR impacts are speculative at this point as it is premature to assume any result until the pilots are conducted and results can be analyzed.

Contrary to Staff and Intervenors' assertions, Mr. Clinton explained that price signals would be clear to customers through usage alerts (warning customers of increased consumption and consequences)[63] and the reasonable usage clause (if the customer increases usage beyond predefined limits, the customer could be removed from the pilot and charged the difference

[63] Customer renewal offers are to be priced predominantly based on customer usage while on the Fixed Bill pilot. If a customer's usage increases, then this would result in a higher monthly Fixed Bill for the subsequent year. Program materials and proactive usage alerts will make the consequences of increased electricity usage abundantly clear for customers (6T 2121, 2124).

between the pilot rate and the D1 rate).[64] Renewal offers for both pilots are to be priced predominantly based on usage while enrolled in either program. If a customer does increase usage, it would likely result in a higher monthly energy expenditure; conversely customers who decrease their usage would likely benefit from lower monthly energy expenditures (6T 2112, 2124). These key elements of the pilots will ensure that customers are aware of and held accountable for the consequences associated with the inefficient use of electricity, and also ensure that price signals are reinforced rather than diluted (6T 2093, 2101-02, 2112-14, 2120-21, 2124).[65]

The PFD points to a prior Commission Order regarding a 2012 proposal made by the Company (PFD p. 246 citing December 20, 2012 order in Case No. U-17054). However, reliance on the previous Commission Order is not relevant here since the program proposed by the Company in this case is different then what was proposed in 2012. In that case, the Commission's primary concern was that the Company requested approval of the program outside of a contested proceeding. Additionally, specific components of the program that the Commission was concerned with in the U-17054 order have been addressed in this proceeding. The Fixed Bill program includes an EWR component with welcome kits that explain energy efficiency programs, provides usage alerts and reasonable use clause (6T 2101-2102), does not impact customers who are not a part of the program (6T 2100), and is based on market research (6T 2097, 2116).

It bears emphasis that the Company's proposed pilots are supported in part by an April 2018 survey of residential customers, which found that 11%, or roughly 218,000 if extrapolated

[64] The Company accepts the PFD's position regarding the reasonable usage clause. Should the Fixed Bill or Weekend Flex pilot receive approval in this rate case, customers could be removed for excessive usage, but would not be required to pay what they would have paid under normal rates.

[65] DTE Electric seeks to learn as much as possible from pilot participants, so the Company would likely exercise the reasonable usage clause only if substantially higher customer usage were systemic amongst the enrolled participants (6T 2115).

across DTE Electric's residential customer class, would actually enroll in the Fixed Bill pilot. This is greater than the enrollment of any other existing residential rate or program outside of the standard D1 residential service rate. Furthermore, 6%, or roughly over 100,000 if extrapolated across DTE Electric's residential customer class, would actually enroll in the Weekend Flex program. Additionally, 28% to 29% of survey respondents, or roughly over 600,000 if extrapolated across DTE Electric's residential customer class, found the Fixed Bill and Weekend Flex Pilots appealing and would want to investigate further. This is a significant and compelling portion of DTE Electric's customer base, and indicates strong customer demand for these offerings (6T 2089-90, 2097, 2116-17). DTE Electric believes that it is imperative to listen to the expressed interests of customers and update pricing options with what customers' desire. That is why the Company conducted its customer survey and is now proposing to pilot programs that explore the expressed interests from the survey results (6T 2125).

The PFD further suggested that the Fixed Bill pilot is duplicative and unnecessary since the Company already offers a BudgetWise Billing program (PFD, p 247). To the contrary, Mr. Clinton explained that the Fixed Bill pilot would provide absolute bill certainty for each 12-month term instead of the quarterly adjustments and annual settlement that may be required under the Company's existing equal monthly billing (BudgetWise Billing). The April 2018 survey also indicated that the majority (55%) of the customers interested in the Fixed Bill option would likely come from current BudgetWise Billing customers. This also shows that there is strong demand for an offering that provides greater consistency in monthly energy spending beyond what BudgetWise Billing affords (6T 2116, 2119-20, 2123).

2. The Weekend Flex pilot should be approved.

With respect to the Weekend Flex pilot, the PFD found that it should be rejected as "largely duplicative of the company's current TOU rate programs, which, as the Attorney General points out, could be modified to provide a larger discount for weekend usage. In addition, the design of the Weekend Flex program is exceptionally complex and could result in significant customer confusion." (PFD, p 247)

The Company disagrees with the PFD's reasoning that the Weekend Flex pilot should be rejected because time-of-use ("TOU") rates could instead be modified. Mr. Clinton explained that the Company's existing TOU rates already incentivize customers to shift usage to the weekend by providing a significantly lower rate during the weekends. DTE Electric also already has variable rate structured time-of-use electric pricing options. These pricing options resonate with certain customers, but the Weekend Flex pilot is unique because it would offer a time-of-use electric pricing option with a fixed component for usage. This fixed-component is a key element that may resonate with certain customers who have otherwise declined DTE Electric's current options. Thus, by offering the Weekend Flex provision, there is the potential for greater overall voluntary enrollment in time-of-use rates (6T 2117-18).

The Company also disagrees with the PFD's assertion that the Weekend Flex proposal "is exceptionally complex and could result in significant customer confusion" (PFD, p 247). Mr. Clinton explained that Weekend Flex would not be much different to explain to customers than existing time-of-use rates D1.8 or D1.2, since all three share the same foundational element of multiple price points varying by time of day and/or day of week (6T 2118-19).

In summary, DTE Electric has listened to its customers, studied the desirability of the pilots and structured them in a manner that the Company believes will increase customer satisfaction, improve future affordability and shift weekday peak usage to low load periods. As such, the

Company believes these offerings are reasonable and prudent and requests their approval. The purpose of these pilots (or any pilot for that matter) is to proceed cautiously and gather information about customer satisfaction, usage behavior, affordability, and Energy Waste Reduction program participation (6T 2103, 2122-2123, 2125). It is inappropriate to simply speculate about the outcome of these pilots before conducting them, and in the absence of any data, case studies or examples to support such speculative conclusions (6T 2112-2113, 2117, 2120-2121). DTE Electric must instead conduct these pilots to gather necessary data regarding how to proceed (6T 2123, 2125). If the PFD and Staff's speculation on the outcome of the pilots turns out to be correct (i. e. increased usage by customers), then the Company would take that into consideration when determining whether to seek approval of these programs on a permanent basis. However, without running the pilot there is no data on which to base these conclusions. Therefore, the PFD's recommendations to reject the pilots should be rejected and the $1.4 million of related O&M expense requested by the Company should be approved.

F. DTE Electric's Primary Rate Design Proposals.

1. The Company's proposed voltage level energy discounts and voltage level demand adjustments reflect the proper allocation of costs of service.

DTE Electric's rates are designed to be cost-based in accordance with MCL 460.11 (5T 1222-23), which states in part "[e]xcept as otherwise provided in this subsection, the commission shall ensure the establishment of electric rates equal to the cost of service to each customer class."

The statute's plain language must be applied as written[66] and DTE Electric's voltage level discounts and voltage level demand adjustments accomplish this requirement. Mr. Bloch explained

[66] *Di Benedetto v West Shore Hosp*, 461 Mich 394, 402; 605 NW2d 300 (2000) ("we presume that the Legislature intended the meaning it clearly expressed - no further judicial construction is required or permitted, and the statute must be enforced as written"); *Hanson v Mecosta Co Road Comm'rs*, 465 Mich 492, 504; 638 NW2d 326 (2002); *Lorencz v Ford Motor Co*, 439 Mich 370, 376; 483 NW2d 844 (1992); and *Ambs v Kalamazoo County Road Comm*,

how the Company's proposed voltage level energy discounts and voltage level demand adjustments for Rates D6.2, D8 and D11 were determined (5T 1223-24; Exhibit A-16, Schedule F12 shows the calculations).[67] He also explained how the Company's transmission-related voltage level demand adjustments for Rates D11 and D8 were determined (5T 1224-25; Exhibit A-16, Schedule F12 shows the calculations).

The PFD instead "recommends that the Commission again approve the Staff's method for calculating demand and energy level discounts" (PFD, p 252). The Company disagrees.

i. Energy-based voltage level discounts.

Staff recommended following the method of determining energy voltage level discounts approved in Case No. U-18255 (Staff Initial Brief, pp 142-64). The PFD agreed, as indicated above, but the PFD's reasoning focuses on demand-based voltage level discounts (and is flawed as discussed below in subsections b and c). Mr. Bloch explained that the Company's proposed method of determining energy-based voltage level discounts allocates energy costs to each voltage level based on loss adjusted sales. Voltage level energy costs are then divided by the corresponding voltage level billed sales to determine the voltage level energy rate from which voltage level discounts are determined. Calculating energy voltage level discounts based on loss adjusted sales at each voltage level better aligns costs with cost causation compared to the method approved in Case No. U-18255 that calculates these discounts by multiplying voltage level loss factors by the

255 Mich App 637, 650; 662 NW2d 424 (2003) ("where the language of a statute is clear, it is not the role of the judiciary to second-guess a legislative policy choice; a court's constitutional obligation is to interpret, not rewrite, the law").

[67] Rate Schedule D11 is the Company's main primary rate schedule and is available to customers served at primary, sub-transmission, or transmission voltage. Rate Schedule D6.2 is available to educational institution customer locations (schools, colleges and universities) desiring service at primary, sub-transmission, or transmission voltage. Rate Schedule D8 is the Company's primary voltage interruptible rate which is limited to 300 megawatts (5T 1221).

class average energy rates. The Company's proposed method is also consistent with past recommendations from ABATE (7T 2848) as the appropriate way to calculate energy voltage level discounts (5T 1256-57). Witness Andrews also confirmed that ABATE would have no objection if the Commission approved DTE Electric's proposed voltage level discounts (5T 2876).

ii. Demand based voltage level discounts.

The Company's proposed methodology for determining demand-based voltage level discounts differs from the method that the Commission approved in Case No. U-18255.[68] The approved method only considers loss differences between voltage levels and does not consider the voltage level cost responsibility to which the losses are applied. The Commission's direction to determine voltage differentiated power supply demand charges should be interpreted to mean voltage level demand charges that are consistent with cost-based principles (as required by MCL 460.11, quoted above), otherwise rate subsidies occur. The Company's proposed voltage level demand rates are cost-based using the same voltage level cost responsibilities that would result by performing a separate power supply voltage level COSS for each rate (5T 1225).

The PFD asserts that "DTE Electric has not shown that its method is cost-based; in fact ABATE's evidence, that under the company's method the discounts or sub-transmission level are greater than those for transmission level, appears to demonstrate the opposite" (PFD, p 252). To the contrary, the Company is the only party in this case (or in Case No. U-18255) that presented a cost-based proposal for determining demand based voltage level discounts. ABATE supported the method of determining demand voltage level discounts approved in Case No. U-18255, following

[68] In Case No. U-18014, the Commission directed: "In its next general rate case, DTE Electric shall calculate a proposed demand voltage level discount for Rates D11 and D8, with the necessary billing determinants, including demand by voltage level" (January 31, 2017 Order in Case No. U-18014, p 132, ordering paragraph M). The Company did so, but the ALJ instead recommended the Staff's method for calculating the discounts, and the Commission adopted the ALJ's recommendation (April 18, 2018 Order in Case No. U-18255, pp 67-69).

the testimony of its witness Mr. Andrews (ABATE Initial Brief, pp 51-53). Mr. Bloch produced evidence that the method approved in Case No. U-18255 is not cost based and produces demand voltage level discounts that increase intra-class subsidies between voltage levels instead of reducing them. This is because, under the current method, voltage level loss factors are applied to the average billing demand charge for the class. However, the costs that make up the average billing demand charge vary by voltage level and Mr. Andrews method does not take this into consideration. To determine demand voltage level discounts without accounting for voltage level cost differences, which are known, does not follow cost of service principles. For example, of the costs allocated to the D11 rate class that are included in the billing demand charge, transmission voltage level customers have a higher relative cost responsibility than subtransmission and primary voltage customers due to their higher relative 4CP demand. Voltage level cost differences are equally relevant to setting voltage level demand discounts as are loss factors and can have a more significant impact than loss factors on demand voltage level discounts. To not recognize the voltage level cost differences based on the 4CP demand would be in stark contrast to how the Company allocates all of its other power supply related capacity costs.

The current method does not account for voltage level cost differences and results in shifting rates further from cost of service basis and increasing intra-class subsidies which runs contrary to the principles of setting cost based rates (5T 1257-58). This shifting is most obvious in Rate D6.2, where the impact of the 4CP cost allocation is much larger than the voltage level loss adjustment. This results in a sub-transmission voltage level adjustment that is a charge rather than a discount under the current method. This same issue impacts all voltage level demand charges that are calculated under the current method (5T 1225-25, 1257-58).

As indicated above, the PFD was persuaded by ABATE's premise that transmission customers have lower loss factors and use less infrastructure than subtransmission customers, which resulted in the proposition that transmission customers have a lower cost to serve. Thus, DTE Electric's methodology appears to produce results that seem counter-intuitive (PFD, p 252). The PFD neglects that during cross examination, ABATE's witness Andrews identified the infrastructure cost savings supporting ABATE's claim that transmission customers have lower cost to serve are distribution related cost savings which are unrelated to and not included in power supply capacity or non-capacity (transmission) costs. With respect to capacity related cost allocation, Mr. Andrews stated "In Michigan, 75 percent of the capacity related costs are allocated on 4CP…" and also acknowledged that cost allocation based on 4CP is more a function of when customers use capacity than what voltage customers take service at. (7T 2880, 2879, 2882)

Mr. Andrews' argument that it is lower cost to serve transmission customers than subtransmission customers is not accurate with respect to determining power supply capacity and transmission cost responsibility because these costs are driven by when customers take service and not voltage level or infrastructure. When given an example comparing a subtransmission customer to a transmission customer, with all things being equal except the transmission customer had a 4CP that was 20% higher than the subtransmission customer, Mr. Andrews agreed the transmission customer should pay a higher rate than the subtransmission customer. (7T 2885). When asked to square this response with his recommendation to only consider voltage level loss factors and not the underlying capacity cost responsibility at each voltage level and with cost foundation principles, Mr. Andrews testified on cross-examination that he had never seen a transmission customer pose more per unit costs than a subtransmission or a lower voltage customer, and that, while the methodology used by the Company attempts to assign and recover cost consistent with

cost causation principles, he believed the underlying data utilized to do so was inaccurate. When asked what about the data was inaccurate, Mr. Andrews could not identify any particular flaw except that it produced results that in his opinion did not "make sense" (7T 2885). Additionally, while Mr. Andrews testified on cross examination that he had never seen a transmission customer responsible for more costs than a subtransmission customer, he admits this is because of the infrastructure costs he identified, as set forth above:

> Q When you say you have never seen a transmission customer responsible for more costs than a subtransmission customer, is that because of the infrastructure argument you made?
>
> A On a per unit basis, yes. [7T 2886]

Considering Mr. Andrews' prior testimony that infrastructure costs are distribution related costs and unrelated to setting capacity voltage level discounts, Mr. Andrews' answer to the above question during cross examination contradicts his position with respect to determining capacity voltage level discounts.

iii. Non-Capacity demand voltage level discounts.

During cross examination, ABATE witness Andrews further agreed that the non-capacity demand charge collects only transmission expenses and that transmission costs are allocated in cost of service 100% on 12CP (7T 2889-2890). He also acknowledged that the 12CP by voltage level can be determined and the methodology of using 12CP by voltage level to determine non-capacity cost responsibility at each voltage level follows cost of service principles (7 T 2890-2891).

The Company's proposal is the only proposal that follows cost-of-service principles by including both loss factors and capacity cost responsibility in determining demand voltage level discounts. It is also the only proposal that reduces intra-class subsidies. Therefore, the

Commission should adopt the Company's proposed changes to the determination of voltage level energy discounts and voltage level demand adjustments, as well as the Company's proposal to add voltage level demand adjustments to the D6.2 Billing Demand charge (5T 1218, 1227).

2. Allocation of Capacity Costs to Rider 3 and Generation Reservation Fee.

i. Rider 3 Cost Allocation.

DTE Electric provides bundled retail standby service to customers with on-site generation under its Standard Contract Rider 3 ("R3"). The Company proposes to change the method of allocating the power supply capacity costs to R3 to account for R3's abnormal demand variability and thereby eliminate the associated subsidy by Rate D11 customers to R3 customers[69]. Mr. Bloch explained that in DTE Electric's next-to-last general rate case, the Commission directed: "In its next general rate case, DTE Electric shall treat Rider 3 as a separate rate class for the purposes of the company's cost of service study" (January 31, 2017 Order in Case No. U-18014, p 132, ordering paragraph N). DTE Electric did so, but presented several concerns with respect to treating R3 as a separate cost of service class, or attempting to allocate power supply costs to R3 on a 4CP [70] basis.[71] The Commission decided against using a separate cost of service class for R3, keeping R3 in the D11/Other COS class (as recommended by the Company), but approved ABATE's recommended allocation of power supply costs for R3, which were based on 4CP data averaged over 10 years (April 18, 2018 Order in Case No. U-18255, pp 72, 76). The latter decision followed

[69] The Company is not proposing to change how costs are allocated to the "D11 and Other Class", which R3, along with D-10 makes up the "other", but is instead more appropriately has determined a sub-allocation of costs to R3.

[70] 4CP is the average of the 4 class demands <u>at the time of the Company's bundled peak hour</u> loads for June, July, August and September. (5T 1233)

[71] "Fundamentally, assigning power supply costs based on 4CP to a standby COS class where loads can be very irregular and can vary significantly at any point in time compared to normal loads, does not follow proper cost allocation principles. This is especially true in a small class, where generation size varies greatly, and one customer can influence the outcome for the entire class." (5T 1232, quoting U-18255 9T 1974).

the PFD's recommendation, which recognized that the Company had a legitimate concern about determining R3 costs based on 4CP, but accepted ABATE's argument that the concern could be addressed by using an average of 4CPs over a longer term (U-18255 PFD, p 276: "DTE Electric's concern that R3 demand variability is not amenable to traditional cost allocation principles is legitimate. However, as ABATE argues, that variability may be normalized by using an average over a longer term") (5T 1232-33. Emphasis added).[72]

The Company maintains that 4CP does not provide an appropriate basis to determine sub-allocating power supply cost to the R3 class, and averaging as ABATE proposed, only masks the resulting subsidization problem. Mr. Bloch provided three tables demonstrating that due to R3's abnormal demand variability, 4CP does not accurately represent the true demands that the R3 class imposes on the system during peak load periods. Table 1 (5T 1234) compares how often a class is operating above its 4CP during high demand on-peak hours 15, 16, 17, and 18 from June through September. These are the summer hours when the Company's 4CPs normally occur. Table 2 (5T 1234) compares the class 4CP to the average of its 4 monthly class peaks during high demand hours (4NCP).[73] This comparison indicates that normal load classes have variances below 10% compared to the R3 class which has a variance that is 108% higher than their 4CP. This means the average of the 4 monthly R3 peak class demands is more than twice their 4CP demand which is over 1,000% higher than normal load classes. Table 3 (5T 1234) compares the class 4CP to the class' highest hourly demand during high demand hours (Class 1NCP during summer hours 15,16,

[72] The Company disagrees that averaging 4CPs that do not correlate with R3 customer actual operational characteristics obtains a "normalized" result. It simply results in a mathematical average that does not represent the demands R3 customers place on the DTE Electric system during peak hours. (See Table 2 at 5T 1234).

[73] 4NCP is the average of the 4 class peak hour loads during hours 15, 16, 17 and 18 for June, July, August and September <u>for each class</u>. (5T 1233-1236).

17 and 18). This comparison also indicates that normal load classes again have variances around 10% compared to the R3 class which has a variance that is 180% higher than their 4CP. These 4CP to 4NCP and 1NCP class load comparisons demonstrate that due to the demand variability of the R3 class, 4CP is not representative of the actual demands R3 places on DTE Electric generation capacity during high demand periods and should not be used to allocate costs to R3 rate class. The currently approved method of averaging 4CPs over several years does not address this variability (its merely a mathematical average having no meaningful connection to the demands placed upon DTE Electric generation to serve these few customers) and results in D11 customers subsidizing R3 customers (5T 1220, 1233-36).

Staff recommended that standby rates should continue to be calculated in the same manner as ordered in Case No. U-18255, reasoning that there is not sufficient evidence to support a change (Staff Initial Brief, pp 146-48). ABATE (Initial Brief, pp 45-51) and MEIBC (Initial Brief, pp 1-14) similarly supported the status quo. The PFD "finds persuasive the recommendation by the Staff, ABATE, and EIBC/IEI, that the power supply cost allocation method approved in Case No. U-18255 should be retained" (PFD, p 255).

To the contrary, the Company presented ample and compelling evidence as indicated above. The PFD was apparently persuaded by Staff's reasoning that any smaller group of customers is going to show more variance than the entire class (PFD, p 253). This makes no relevant point. Mr. Bloch explained that the appropriate question is whether actual 4CP demand is an appropriate allocator for the R3 rate class. As indicated above, R3 has more variance than would be expected for a subgroup of D11 customers. This demonstrates that actual 4CP demand is not an appropriate allocation method for allocating capacity costs to R3 (5T 1251).

The PFD was also persuaded by Staff's alternative suggestion that it is possible that actual 4CP is a poor allocator for D11, and 4CP could make a reasonable allocator when all rate schedules are considered in total (PFD, p 253-54). To the contrary, Tables 1, 2 and 3 demonstrate that actual 4CP is an appropriate allocator for D11, in line with all other cost of service classes (5T 1251).

MEIBC/IEI asserted that the Company's proposal to use an equivalent 4CP moves away from cost causation principles and arbitrarily allocates power supply costs, and the PFD agreed (PFD, p 255). However, MEIBC/IEI provided no supporting evidence to support their claim and their witness confirmed that she has never performed a cost of service study (5T 1251; 8T 3490-3491). Thus, there is no proper evidentiary basis to rely on EIBC/IEI's opinion concerning Rider 3 cost allocation.[74]

The PFD was also apparently persuaded by ABATE witness Mr. Dauphinais, who offered five bullet points to attempt to support his suggestion that the Company's arguments are somehow flawed (PFD, p 254). Mr. Bloch responded by explaining why each point failed to support the argument. Instead, the Commission can and should approve a power supply cost allocation method for R3 that best represents the Company's costs to serve this class and is consistent with power supply cost allocation to other classes. Only the Company's proposal accomplishes this outcome (5T 1248-50).

On cross examination, Mr. Dauphinais agreed that ABATE supports cost of service and rate design principles that reflect cost causation and does not support rate designs that do not reflect cost-causation or that shift cost of service away from cost-causation (6T 1787). Mr. Dauphinais

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[74] MCL 24.285; *Ludington Service Corp v Comm'r of Insurance*, 444 Mich 481, 483, 494-97, 500-501, 507; 511 NW2d 661 (1994), *amended* 444 Mich 1240 (1994); *In re Complaint of Pelland*, 254 Mich App 675, 685-86; 658 NW2d 849 (2003).

agreed that ABATE cannot tell exactly when the Company's peak loads will occur in the future, but agreed that the peak loads will be during the summer typically June through September and typically during hours 15, 16, 17 or 18 (6T 1791). Mr. Dauphinais further agreed that the 4CP column in Table 2 for all classes shown, except R3, is a reasonable way to allocate capacity costs to those classes (6T 1793), and that applying the R3 108% variance to the D3 &Other class would result in an extraordinary increase in capacity requirements from 133MW to over 1,500MW (6T 1793, 1795). Notwithstanding these acknowledgements, Mr. Dauphinais did not agree the values shown in Table 2 under the column labeled "Avg of Monthly Max Hrs" reflects the 4NCP for each class. Mr. Dauphinais incorrectly asserted "it's the average of the demands in hours 15, 16, 17 and 18 for all non-holiday weekdays of the summer period of June, July, August, and September, that's not a non-coincident peak value" (6T 1792). However, 4NCP is the average of the *4 class peak hour* loads all during hours 15, 16, 17, and 18 for June, July, August and September for each class (5T 1233-1236), not the "average of the demands in hours 15, 16, 17 and 18 for *all non-holiday weekdays of the summer period…"* (6T 1792. Emphasis added). The values shown in Table 2 in Witness Bloch's testimony under the column labeled "Avg of Monthly Max Hrs" reflect the 4NCP for each class determined during the hours 15, 16, 17 and 18, non-holiday weekdays, for months June, July, August and September (5T 1235). Thus, it appears ABATE's position (and the resulting PFD recommendation) is based on a misunderstanding of the data shown in that table.

To properly sub-allocate capacity costs to the R3 class, the Company recommends calculating an equivalent 4CP demand for the R3 class by taking its actual 4NCP demand shown in Table 2 and reducing it by a variance adjustment in line with normal system load classes, which all operate with variances below 10%. Using 10% results in an equivalent 4CP demand of

approximately 16MW. Allocating capacity costs on this basis results in a capacity revenue requirement for R3 of $3.895 million (5T 1236).[75]

The Company's proposal does not affect how costs are allocated in the COSS since R3 is included in the D11/Other cost of service class. The proposal only affects the revenue requirements of R3 and D11. To the extent that the revenue requirement presently assigned to R3 understates the cost to serve R3, it shifts revenue requirement/cost responsibility to D11, causing D11 customers to subsidize R3 customers. The Company's proposed capacity revenue requirement eliminates the current D11 subsidy to R3 that resulted from allocating capacity costs to R3 based on an arbitrary 10-year average of their 4CP. The Company's proposed method of allocating capacity costs to R3 accounts for R3's abnormal demand variability and results in proper cost allocation to R3 pursuant to MCL 460.11(1). Therefore, the Company's proposal should be adopted (5T 1220-21, 1237).

ii. Generation Reservation Fee.

DTE Electric also proposes to change the basis for setting the generation reservation fee approved in Case No. U-18255 due to both cost of service and rate design concerns (5T 1232, 1237). The Commission adopted ABATE's proposal to set generation reservation based on the best performing generators of R3 customers (April 18, 2018 Order in Case No. U-18255, p 77: "The Commission finds that it is reasonable to approve an R3 standby tariff that sets a monthly power supply reservation charge based on the forced outage rates of the best performing generators"). The Commission did not specifically address the Company's concerns that

[75] Neither Staff nor any intervenor provided cost analysis or data to support their positions with respect to R3. In contrast, the Company provided empirical evidence in support of its proposal to allocate capacity to R3 using an equivalent 4CP demand (5T 1232-39, 1251-52).

availability is not an appropriate basis to set the generation reservation fee since availability does not reflect generator performance and the Company's need to reserve capacity.

From a cost-of-service perspective, the premise that if a generator has a forced outage rate of 3.5%, then the generator will fully serve its' load requirements the remaining 96.5% of the time is not accurate due to operating costs and other operational considerations. Mr. Bloch compared three of the Company's largest R3 standby customers, which all have annual availabilities of 98% or higher. Their standby service use was not in the 2% range (as the above would suggest); instead their actual average annual standby requirement was 30%, with a range from over 17% to over 50%. These customers also represent over 75% of the R3 class sales, so the results are representative of the R3 class. These results demonstrate that availability does not indicate how well a customer's generator serves its load and, therefore, does not represent the standby requirements that the customer places on the system (5T 1238, 1252-53). The PFD disagreed, stating: "As this PFD found above with respect to the power supply cost allocation, the method for determining the reservation charge should be retained" (PFD, p 258).

As noted in the PFD, ABATE witness Mr. Dauphinais suggested that setting the R3 monthly generation reservation fee based on the best generator availability is reasonable because the fee is a minimum required contribution toward fixed power supply costs that must be paid regardless of how much standby service power is actually taken by the customer (PFD, pp 256-57). Mr. Bloch explained that Mr. Dauphinais' proposal to set a generation reservation fee based on the forced outage rate of the best performing generators is fundamentally flawed since forced outage rate is not a measure of, nor indicative of, generator operating performance (5T 1252). In fact, none of the parties promoting this position provided any supporting evidence demonstrating a linkage between forced outage rate (generator availability) and generator performance.

The PFD also cited MEIBC/IEI's arguments (PFD, 257), but its witness acknowledged that the Company is required to stand ready to serve the entire load of the R3 customer irrespective of the fact they have a generator on site and that a generator with 97% availability might be operating at 25 percent of its nameplate capacity at any given time (8T 3504, 3506). [76] Additionally, Witness Dauphinais acknowledged that the Company has no control over customer on-site generation through R3 and the customer with on-site generation has no obligation or requirement to operate its generation even to serve its own load (6T 1798).

In contrast, the record evidence outlined above demonstrates that forced outage rate is not an indicator of generator performance. Even apart from this evidence, the recommendation to set a generation reservation fee based on the best performing generator is an exception from the normal rate design practice of setting rates based on average performance. This is like asking a car insurance company to set collision rates based on their best driver, and if that driver never had an accident, then the premium for collision insurance should be zero. This methodology should be rejected as incorrect and contrary to cost causation principles (5T 1253-54, 1256).[77]

Further, the current R3 rate design has constrained the R3 rate design by having all R3 demand charges based on the D11 billing demand (April 18, 2018 Order in Case No. U-18255, p 77). This limits the ability to design R3 capacity rates equal to R3 costs, which are not determined based on the D11 billing demand. Therefore, and as discussed above and further explained on the

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[76] EIBC/IEI further indicated a concern that "the Company proposes to remove the requirement to take into account a CHP system's availability when calculating the generation reservation fee" (8T 3476). The indicated concern does not accurately reflect the Company's position. Instead, that position has been, and continues to be, that setting a generation reservation fee based solely on lowest forced outage rate (highest availability) is flawed, arbitrary, does not follow cost-causation principles (5T 1255-56).

[77] This is an apt analogy because the best performing generator in the R3 group has an availability of 100% (5T 1238). Mr. Dauphinais suggested that this 100% availability (i.e., a 0% forced outage rate) is a "red herring" (6T 1754). To the contrary, this fact is a reality that exposes the potential consequences (subsidization by other D11 customers contrary to cost based ratemaking) of following Mr. Dauphinais's theory (5T 1254-55).

record and in DTE Electric's Initial Brief, the Commission should remove the requirement to set the generation reservation fee based on generator availability and allow changes in R3 capacity revenue requirement to be collected through the generation reservation fee (5T 1239).

3. Rate D1 Time of Use rate design (summer on-peak non-capacity charges).

The Commission previously directed the Company to include a proposal to redesign its residential rates in its next rate case (this case) (April 18, 2018 Order in Case No. U-18255, pp 81-82, and p 86, Ordering paragraph E). DTE Electric moved for rehearing, pointing out that even if the directive were clarified for accuracy,[78] it still would have unintended consequences by defaulting approximately 1.9 million customers to time-based rates for non-capacity charges with significant impacts on the Company's rate structure and individual customers' bills. The Commission granted the request for clarification, re-affirmed the substance of its decision, and left implementation issues open to further consideration (June 28, 2018 Order on Rehearing, p 7).

i. The Commission should reverse its prior ruling.

The Company complied with the Commission's directive (as discussed below), but maintains its position from Case No. U-18255 and requests that the Commission reverse its prior ruling. The PFD noted the issue, but proceeded to discuss other matters (PFD, p 258). Thus, the PFD implicitly recommended denying DTE Electric's request.

DTE Electric maintains that it should able to retain its existing Rate D1 pricing schedule because customers should be allowed to choose to opt-in voluntarily to any new and significantly-different rate program. The Company also proposes D1 and D1.6 rates using the existing rate structure in anticipation that the Commission will reverse its prior decision and allow the Company

[78] The D1 non-capacity rate is a flat per kWh charge, not an inverted block rate as indicated in the April 18, 2018 Order.

to retain its existing Rate D1 pricing structure, and alternatively because there will be a long lead time to facilitate the change Company-wide. The existing rate structure would need to stay in place until all customers can be transitioned to the new rate structure (3T 85-86; 8T 3866).

The Company currently offers several different residential rates, so customers have a wide range of options, including whole home TOU rates, interruptible air conditioning, dynamic peak pricing, and geothermal rates. If customers believe they can take advantage of savings related to a TOU rate structure, or any other rate program, then customers will opt-in. Customers should not be forced onto TOU rates. The Commission's presently-ordered change in the residential rate structure will also have significant operational and financial impacts on the Company in several areas including information technology, customer service, and marketing and communications (3T 84-85). If the Commission does not reverse its prior ruling, however, the PFD recommended that the Company recover its costs of transitioning to TOU rates (PFD, p 260).

ii. The PFD/Staff's recommendation that the Company explore shadow billing should be rejected.

Staff suggested that the Company explore shadow billing (8T 4146).[79] The PFD "agrees with Staff that, in the company's next rate case, DTE Electric should be directed to present a plan for implementing shadow billing for customers wishing to explore different rates" (PFD, p 261).

The Company does not agree that shadow billing would be appropriate in this situation due to the precise and complex calculations needed to render an alternative bill. The Company is also not convinced that backwards-looking shadow billing functionality is helpful. Instead, a rate calculator (of some form that balances complexity, costs, and effectiveness) that helps customers

[79] Shadow billing is a billing practice that calculates a customer's bill using their actual, historic billing determinants as if the customer were on a different rate, such as a time-of-use rate. (8T 4146).

forecast costs would be a more useful tool for educating and informing customers on how the different rate options will impact their electric bills (6T 2129).

The PFD offered only the following reasoning for its recommendation: "As the Staff points out, the use of actual data, as opposed to theoretical comparisons is more likely to increase customer interest in alternative programs" (PFD, p 261). However, there is nothing in the record to support this position. Reasoning that shadow billing would be "more likely to increase customer interest in alternative programs") is also inapplicable to this situation where TOU rates are mandated, as discussed above.

iii. The PFD's recommendations to study alternative rate structures should be rejected.

DTE Electric complied with the Commission's directive to develop a time-based non-capacity rate for Rate D1, and (assuming for argument's sake that the Commission does not reverse its prior ruling) largely agrees with the PFD regarding rate structure, noting that "[a]s DTE Electric points out, the Staff's and MEC/NRDC/MEC's recommendations do not comport with the Commission's order in U-18255." (PFD, p 264) Nevertheless, the PFD goes on to recommend that Staff's proposal be explored further in the Company's next rate case. The Company disagrees with this recommendation. The PFD rejected Staff's proposal recognizing that it does not meet the requirements in the Commission's prior order, so it is unclear what benefit would be achieved in studying it further. This is especially true since the Company will not have studied the impact of customers' reactions to the new TOU pricing. If the Staff (or anybody else) wants to make a proposal in the future, then they are certainly free to do so (subject of course to applicable legal and regulatory requirements). DTE Electric particularly objects to the extent that the PFD can be read to suggest that the Company should have some initial burden of either presenting evidence or proof on another party's flawed and rejected proposal.

Although *res judicata* and collateral estoppel do not apply "in a strict sense" to the Commission's ratemaking decisions, "issues fully decided in earlier PSC proceedings need not be 'completely relitigated' in later proceedings ***unless the party wishing to do so establishes by new evidence or a showing of changed circumstances that the earlier result is unreasonable***." *Application of Detroit Edison to Implement Opt-Out Program*, unpublished opinion per curiam of the Court of Appeals, issued February 19, 2015 (Docket Nos. 316728 and 316781), *lv den* 499 Mich 868 (2016), *reh den* 499 Mich 972 (2016). (Opinion affirming AMI opt-out charges, p 8, citing *Application of Consumers Energy Co*, 291 Mich App 106, 122; 804 NW2d 574 (2010), which quoted *Pennwalt Corp v Public Service Comm*, 166 Mich App 1; 420 NW2d 156 (1988). Emphasis added).

More recently, in response to an argument raised by RCG that the opt-out charges should be reduced to zero, the Court of Appeals explained:

> In this appeal, [RCG] again argues that the opt-out charges should be eliminated. [RCG] first contends that there was no evidence presented in the current proceeding supporting the amount of the fees. The reason for this was simple: DTE was not seeking to alter the opt-out fees, which had been set in Case No. U-17053. As the MPSC has explained previously, there is no need for the MPSC to take new evidence on an issue that has been decided previously, absent a showing that circumstances have somehow changed. [*Application of DTE Electric Company to Increase Rates*, unpublished opinion per curiam of the Court of Appeals, issued October 25, 2018 (Docket No. 338378), reh den December 27, 2018, following *In re Consumers Energy Co App*, 322 Mich App 480, 493-94; 913 NW2d 406 (2017) and *Pennwalt Corp, supra*, 166 Mich App at 9.]

These principles also apply here, since the record demonstrates that Staff's proposed price differential should be rejected. The Company's proposed price differential between on-peak and off-peak rates is based on the historic summer MISO locational marginal price ("LMP") in cents per kWh (5T 1344; 8T 3864, 3883). Staff "recommends that the differential be applied as a percentage rather than a nominal difference" (Staff Initial Brief, p 153). Mr. Dennis explained that

the Company's proposed methodology provides a more accurate portrayal of the difference in LMP price (8T 3883-84).

Implementing a larger differential than the Company proposes could have a negative impact on customer acceptance and satisfaction, and would significantly increase revenue recovery risk (*i.e.*, the larger the differential, the higher the revenue impact if customers change usage behavior differently than expected).[80] The Company does not forecast any load shift away from on-peak hours for the projected test year, due to the time necessary to implement IT changes, as indicated above, and also in part because of the differential the Company proposed (a 1 cent per kWh on peak / off peak price differential). If the TOU structure proposed by the Company is implemented for Rate D1, then the Company will study how customers react to the new rate structure and analyze whether it should be modified in future cases (8T 3865, 3884-85).

iv. The Company's "Recommended Plan" to TOU rate implementation should be adopted.

If the Commission does not grant the Company's request as discussed above in subsection a, then the Company should be allowed to proceed with implementation over a reasonable time period based on the scope of work involved (3T 85). DTE Electric offered a Recommended Plan and an Alternative Plan for transitioning residential customers to a summer on-peak rate.

The Recommended Plan allows for piloting multiple rates to allow for a more comprehensive assessment of potential rate designs. The Alternative Plan allows for the piloting of only a single rate in phase one, unlike the Recommended Plan which allows for piloting multiple

[80] Staff's alternative proposals (to convert the capacity charge to a TOU rate, and to use the percentage LMP differentials to determine the on peak / off peak differentials) would result in a price differential that is almost four times what the Company proposed. This substantial price differential could have a negative impact on customer acceptance/satisfaction and would increase revenue recovery risk, yet Staff did not address how its proposed price differential would affect usage (8T 3884-86).

rates. Piloting only a single rate results in a projected go-live date of June 2021 compared to May 2022 for the Recommended Plan. The Alternative Plan provides less time to gather information and study customer behavior due to summer on-peak rate changes, and to develop solutions to potential issues identified during the pilot phase (3T 101-102).

Staff recommends that the alternative plan be approved (Staff Initial Brief, p 155) and the PFD agreed, stating:

> The ALJ finds the Staff's position persuasive. There does not appear to be a need to pilot a number of different rate design alternative[s], especially given the finding above that the company's more modest rate design proposal was reasonable and should be adopted. In addition, the ALJ agrees with the Staff that many of the company's proposals are related to other residential programs such as TOU and critical peak pricing that can be piloted at any time. [PFD, p 266.]

The Company disagrees with the PFD/Staff's assertion that there is no need for testing. Mr. Stanczak testified that Staff's underlying testimony is unsupported and contrary to the research and best practices provided in Staff's own Exhibit S-16.1 (3T 103). He further explained that it is important to get each customer on the right rate and provide for potential opt-in rate alternatives. The Company must analyze and understand the impacts to customers for whom a summer on-peak rate is not feasible or appropriate. For example, customers who cannot shift load without significant adverse impacts, customers who should not shift load due to unique health reasons, and customers who should be aware of other rate options. Therefore, it is necessary to pilot multiple rates and evaluate results to determine customer implications from a summer on-peak rate compared to other opt-in rate alternatives. It would also be missed opportunity for a comprehensive assessment of rate design that benefits customers in the long term during the rate transition period (3T 102). The suggestion that proposals can be piloted at any time neglects the fact that timing

matters. Study results are moot if action is taken before these results are known so that they can be used to determine what action is appropriate.

The Recommended Plan also provides additional benefits. Multiple policy goals and objectives may be achieved through a comprehensive rate design assessment that results in both new opt-in rate options and default rates. The Recommended Plan includes additional objectives and benefits, such as: (1) understanding customer behavior and peak load reduction and to assess feasibility and attractiveness of alternative rate designs; (2) billing analysis to determine appropriate on-peak/off-peak pricing ratio and impacts to customer affordability; and (3) testing multiple messages that encourage load shifting among different customer segments (3T 103).

G. DTE Electric's Distributed Generation ("DG") program tariff (Rider 18) is reasonable, equitable and consistent with MCL 460.6a(14) and should be approved.

DTE Electric proposes a new distributed generation ("DG") program tariff. The Commission's April 18, 2018 Order in Case No. U-18383 stated that in any rate case filed after June 1, 2018, utilities must file the DG Inflow/Outflow tariff attached to that Order. Exhibit A-16, Schedule F10.1 fulfills that obligation, and includes some necessary changes to conform the tariff for DTE Electric. The Company does not propose approval of that tariff, however, as the Commission also stated that "the utility may also file its own alternative DG tariff" (April 18, 2018 Order in Case No. U-18383, p 16). The Company has done so, and requests approval of its proposed DG Program tariff, which is included as part of Exhibit A-16, Schedule F10 Revised (8T 3874-77).

The Company's proposed Rider 18 utilizes an "inflow/outflow" pricing mechanism, with a System Access Contribution ("SAC") charge and is designed to eliminate cost shifting from DG

customers to non-DG customers. This is consistent with cost of service principles (8T 3593-95) as well as Section 6a(14) of Public Act 341, which states:

> Within 1 year after the effective date of the amendatory act that added this subsection, the commission shall conduct a study on an appropriate tariff **reflecting equitable cost of service** for utility revenue requirements for customers who participate in a net metering program or distributed generation program under the clean and renewable energy and energy waste reduction act, 2008 PA 295, MCL 460.1001 to 460.1211. (MCL 460.6a(14)) (Emphasis added)

1. The Inflow/Outflow tariff is the appropriate basis for the Company's proposed DG tariff (Rider 18).

DTE Electric proposes the following "inflow/outflow" pricing mechanism. For all energy that a Distributed Generation tariff customer (DG customer) inflows (*i.e.*, receives from the Company), the customer will be charged the full retail rate of the rate schedule to which the customer attaches Rider 18. For all energy that a DG customer outflows (*i.e.*, sends to the Company's distribution system), the DG customer will receive an outflow credit that is the monthly average real-time locational marginal price ("LMP") for energy at the appropriate DTE Electric load node. The PFD agreed in part, recommending "that the inflow charge be set at the DG customer's full service rate" (PFD, p 274), and that only the outflow credit recommendations proposed by DTE Electric and Staff merit consideration in this case (PFD, pp 274-75; DTE Electric maintains its position on the outflow credit, as discussed below).

The PFD also made a number of additional "initial findings of fact and conclusions of law" (PFD, p 272). DTE Electric does not disagree with the PFD's general statements as the Company understands them, but reserves the right to present a more nuanced discussion in response to other

parties' exceptions or otherwise as the issues are further discussed.[81] DTE Electric also disagrees with some of the PFD's specific recommendations, as discussed below.

2. The System Access Contribution ("SAC") Charge is cost-based, equitable, non-discriminatory and should be approved.

DTE Electric's proposed SAC charge is a proposed monthly charge per kW of installed nameplate capacity on the customer's site, as calculated on Exhibit A-16, Schedule F9. The SAC charge would apply only to DG residential and commercial secondary customers on a rate schedule that has distribution charges based on kWh consumption. Customers on rate schedules with demand-based distribution rates would not be subject to the SAC, since demand charges more appropriately recover distribution costs (8T 3598-3601, 3875-76).

The PFD agreed with the parties opposing the SAC charge, stating:

> The PFD agrees with the parties opposing the SAC. The record supports the claims of the opposing parties that the SAC charge is not COS-based, despite the company's protestations to the contrary. Although the SAC charge is ostensibly designed to recover costs associate[d] with DG customers' more extensive use of the grid, as attested to by Mr. Serna and Mr. Mueller, as multiple parties point out, the cost is actually designed to recover lost revenues resulting from customers' decisions to invest in DG. As ELPC argues, "DTE's methodology explicitly relies on 'revenue deficiencies' and not cost of service[,]" pointing to "Ex. A-16, Schedule F9, Lines 8-9 (calculating 'annual distribution revenue deficiency' and 'monthly distribution revenue deficiency' for purposes of calculating the SAC). Lost revenues are not the same thing as cost of service."
>
> Because the DG tariff approved under Section 6a(14), must be COS-based, and a tariff including a SAC is not, it is not necessary to reach a determination on whether the SAC charge is "equitable" as the statute also requires. Briefly, however, and for completeness, the SAC charge is also not equitable. The fact that the SAC charge is not based on a DG customer's actual usage of DTE Electric's distribution system but rather on the size of the customer's system. [PFD, pp 285-86. Footnotes omitted.]

The Company takes exception as discussed below.

[81] The issues are also discussed in detail in DTE Electric's Initial and Reply Briefs, which are incorporated by reference for a fuller discussion of the issues, as well as in response to other parties' anticipated exceptions.

i. *Without the SAC, the Company would not recover the full cost of DG customers' distribution infrastructure use.*

The PFD's discussion skips over the whole point of the SAC charge, which is that DG customers should pay for the distribution infrastructure they use. The PFD instead focuses on criticizing the SAC methodology (which is inaccurate as discussed below), but it is important to keep in mind throughout this discussion what the PFD is really recommending – that DG customers pay nothing despite the facts that (1) their inflow (and the resulting Company cost recovery) is reduced by the intermittent on-site usage of intermittent on-site generation; yet (2) the Company's fixed distribution system is and must <u>always</u> be available to serve the DG customer if the customer's generation system goes down and to balance, second by second, the changes in the intermittent generation from the distributed generation system (8T 3897-98).

The PFD does not recognize this suggest that DTE Electric quantified the costs associated with the SAC, stating:

> To provide some scale to the company's claims, the ALJ notes Mr. Serna's testimony: "Across a survey of five states and six utilities, and with cost shift studies conducted by various parties including utilities, external experts, and state utility commissions, the estimated range of distributed generation induced annual cost shift is $444 to more than $1,700 per [non-DG] customer." 8 Tr 2594. Although somewhat dubiously sourced, assuming this information were accurate, the purported subsidy paid by non-DG customers would range from about $0.50 to $1.90 (if Michigan were as sunny as Arizona) per customer per year. [PFD, p 274, n 666.]

The evidence entered in this case shows that there would be cost-shifting (non-DG customers would subsidize DG customers) without the SAC. Mr. Serna explained that there is a bidirectional relationship for distributed generation interaction with the grid, which is a physically different relationship than that of a non-DG customer. This relationship and the services provided by the grid are discussed in detail in the Electric Power Research Institute ("EPRI") report titled "The Integrated Grid" (Exhibit A-34, Schedule X-5). This EPRI report recognized that DG

customers receive significant value from grid services (8T 3670), and highlighted five services that the grid provides to DG customers: 1) reliability (the grid serves as a rebalancing resource to offset variable and uncertain output from distributed generation resources; 2) startup power, i.e., the grid provides instantaneous power for appliance startup that a PV system may not; 3) voltage quality; 4) efficiency, which allows a DG resource to run at its optimum level without having to adjust its output based on local load variation; and 5) energy transaction, or the ability to install any size DER that can be connected to the grid (8T 3671-72). There was no party that disputed the services provided by the grid or the results from the EPRI report.

Company witness Mueller testified that the average DG customer uses the grid more than a non-DG customer and may actually add costs to the distribution system (8T 3804 - 3807). This is in part due to the DG customer's export of power onto the local grid (8T 3805). Mr. Serna also testified that the Company has demonstrated that DG customers have a summer net peak demand half a kW greater than the traditional residential Rate Schedule D-1 customers (See Exhibit A-16, Schedule F11) (8T 3650).

The SAC accounts for all DG customers having 24/7 optionality to use the full capability of the electric system (8T 3596). The costs have traditionally been recovered volumetrically, and a portion of grid costs would still be recovered though the inflow charge. With the lower inflow of DG customers, however, utility infrastructure costs would remain unrecovered and be shifted onto the remaining traditional customers without the additional SAC (8T 3599). This concept has been recognized by experts and many other jurisdictions are considering similar charges (8T 3596-97). Mr. Serna explained the need for this charge and thatDG customers also have a significantly different load shape than traditional customers, and their bidirectional relationship with the electric system is a fundamental distinction from traditional customers (8T 3591-92). Thus, without the

SAC, Rider 18 customers would avoid paying distribution costs, which represents a continuation of the cost shift that the new DG tariff is intended to address (8T 3890, 3894-95).

The PFD did not recognize that the SAC would be recalculated based on updated cost and usage data with each rate case (8T 3894). The SAC is also appropriately tailored to each customer's use of the distribution system because it is dependent on each DG customer's installed capacity (8T 3895)[82] thus it is an appropriate charge to recover the costs that DTE Electric incurs to serve DG customers.

Mr. Mueller responded to various assertions by witnesses attempting to justify continuing DG subsidization (8T 3803-17). He stated that:

(1) An average DG customer uses the grid more than a non-DG customer (8T 3804-3806);

(2) An average DG customer does not use most of its own production on site to serve its own needs (8T 3805-3806);

(3) DG customer solar operation does not substantially coincide with times of peak load on the system in the Company's service territory (8T 3806-3808);

(4) The proposition that there are insignificant system upgrade costs and impacts below 5% DG system penetration lacks any sound foundation (for example due to design flaws in an underlying cost study) and is inaccurate (for example because DG installations tend to be clustered, raising the local penetration and potentially overloading the transformer and raising the local voltage, while the feeder level generation percentage would remain small). (8T 3808-13);

[82] The Commission has also approved numerous charges that are fixed in nature (for example, the Service Charge), and all the Company's rates are based on averages to some extent. Rates are not designed for each individual customer separately based on their specific use of the system (8T 3895).

(5) The proposition that DG customers off load the grid and can thus be used to satisfy load growth and reduce grid investment is inaccurate. DG customers may offset some of their own load, but they do not do so at peak times. Generation must also be schedulable and dispatchable (available and reliable when needed) to offset grid investment. DG does not meet these criteria. Instead, it is entirely dependent on the season, time of day and weather and cannot produce power outside of solar hours. Indeed, these characteristics of intermittent DG generation cause problems that require additional grid investments to maintain service, as recognized in the same MIT solar report referenced by Mr. Kenworthy (8T 3813-14).

(6) There are significant grid impacts from the integration of DG into the distribution system, as reflected by the Company's discovery responses (relevantly compiled in Exhibit A-43, Schedule GG-2), which highlight the range of grid impacts that DG imposes on the distribution system, including: (1) local costs for upgraded services, secondary and transformers; (2) protection-related costs for changes to fuses, relays and reclosers and their settings; (3) voltage support related costs from settings changes to regulators or capacitors or potential installation of new devices; and (4) additional operating costs from switching and safely working around distributed generation including during restoration. DTE Electric stands by its discovery responses regarding these DG issues. Moreover, these are not just issues that the Company identified - others have identified the same issues (8T 3814-17. See also 8T 3650-53, 3664; Exhibit A-16, Schedule F11, Exhibit A-34, Schedule X-3).

DTE Electric also notes that those parties advocating for continuing cost shifting to other DTE Electric customers neglect that the Commission lacks authority to authorize cost shifting to subsidize

the DG industry[83] and the Legislature has mandated the transition away from subsidized net metering rates (*e.g.*, 8T 3593-96).[84]

When viewed in light of the controlling law and record evidence, it becomes apparent that the SAC charge appropriately seeks to make DG customers pay for costs that they cause. The PFD's recommendation that DG customers instead pay nothing (which effectively means that non-DG customers would have to pay the DG costs instead) should be rejected.

ii. The SAC is cost-based.

The PFD opined that DTE Electric's SAC proposal is not cost-based, but instead seeks to recover lost revenue from energy that the Company would not supply to a DG customer (PFD, p 285, quoted above). The PFD was apparently persuaded by ELPC and is accurate to the extent that it recognizes that volumetric charges to DG customers will be reduced, but ignores that volumetric inflow rates do not fully account for utility costs incurred on behalf of DG customers). However, this results in distribution costs not being recovered from these customers absent some other mechanism like the SAC. Distribution costs not recovered from DG customers represent a cost shift and burden

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[83] The MPSC has no common law powers, but only possesses the limited authority that the Legislature conferred upon it. *Consumers Power Co v Public Service Comm,* 460 Mich 148, 155; 596 NW2d 126 (1999). The MPSC is an "administrative body created by statute and the warrant for the exercise of all its power and authority must be found in statutory enactments." *Union Carbide v Public Service Comm,* 431 Mich 135, 146; 428 NW2d 322 (1988); *Sparta Foundry Co v Public Utilities Comm,* 275 Mich 562, 564; 267 NW 736 (1936). The MPSC's authority must be conferred by clear and unmistakable statutory language, and a doubtful power does not exist. *Mason Co Civil Research Council v Mason Co,* 343 Mich 313, 326-27; 72 NW2d 292 (1955). The MPSC cannot expand its jurisdiction through its own acts or assumption of authority. *Ram Broadcasting v Public Service Comm,* 113 Mich App 79, 92; 317 NW2d 295 (1982).

[84] Mr. Jester further suggested that even if all DG customers were net metered and did not pay any portion of the retail rate, and that the utility is unable to avoid any costs as a result, then the maximum effect would be to shift about 1% of costs to other customers, (6T 2202-2203). Mr. Dennis disagreed, explaining that the Company is proposing Rider 18 to comply with state law requiring the Company to file a cost-based and equitable distributed generation program tariff. Regardless of the number of DG customers, if customers are not covering the cost for the services and infrastructure they are utilizing, then those costs will be shifted to other non-DG customers (8T 3904**).** Mr. Serna further discussed DG customers' usage ("net load") profiles and net load shape as reasons why the level of distributed generation penetration should not be a factor in defining a new DG tariff (*e.g.*, 8T 3668-69, 3674-75).

imposed on non-DG customers. The Company's proposal moves away from the cost shifts associated with net metering to properly cost-based rates in accordance with well-established ratemaking principles and as required by 2016 PA 342 (8T 3676-77). The PFD elsewhere recognizes that delaying the implementation of cost-based DG rates is not a viable option (PFD, p 274).

The SAC is also supported by cost of service evidence on the record. Mr. Dennis explained that the SAC was designed to recover fixed costs of the distribution system for both residential and commercial secondary customers. The distribution costs being recovered are developed by the Company's cost of service witness Mr. Lacey (Exhibit A-16, Schedule F-1.2). Based on the revenue requirement for these classes, DTE Electric developed a cost-based distribution charge (line 5, Exhibit A-16, Schedule F9) which was used in development of the SAC. Thus, the SAC is cost based (8T 3898; Exhibit A-42, Schedule FF2). The SAC is designed using the Company's distribution cost of service study (numerator) and the Company's forecasted load (denominator) so that the Company will recover its revenue requirement, nothing more or nothing less (8T 3899). The PFD's allegation that, "lost revenues are not the same thing as cost of service" (PFD, p 285) in this instance is inapplicable. The Company did not argue SAC revenues should be recovered simply because they are "lost" – the Company has shown, as explained above, the revenue proposed to be recovered by the SAC is based on the amount the cost of service study shows these customers should be paying based on the services they receive and the costs the company incurs to provide those services.

The PFD suggests that the proposed SAC represents a "double-recovery of the utility's costs to deliver the DG exports" (PFD, p 284, quoting Mr. Kenworthy at 6T 2336). To the contrary, Mr. Dennis explained that the SAC would not compensate the Company for a DG customer's outflow and would not double charge for distribution services. The Company calculated the SAC

charge by utilizing on-site consumption, which does not include customer outflows (Exhibit A-16, Schedule F9). Under the Company's Rider 18 proposal, no charge is designed to apply distribution charges to DG customers for outflow (8T 3898).

iii. The SAC is not discriminatory.

The PFD suggests that the SAC is not equitable because it treats DG customers differently than non-DG customers (PFD, pp 285-86, quoted above). To the contrary, there is nothing inappropriate about treating different things differently,[85] and DG customers are plainly different than other customers, as discussed above (for example, DTE Electric Witness Serna explained that there is a bidirectional relationship for distributed generation interaction with the grid, which is a physically different relationship than that of a non-DG customer at 8T 3671-72).[86]

As explained above, the SAC is designed to only recover DG customers' allocable costs of the Company's distribution system (8T 3898-99). The Company's proposed Rider 18 is also just one of the various rate offerings that customers can choose if it suits their purposes.[87]

iv. DG customers are not comparable to customers who reduce consumption through energy efficiency or demand response measures.

The PFD suggested that the proposed SAC would inappropriately treat DG customers differently than non-DG customers, because both types of customers have variable usage (PFD, p 286, quoted above). Mr. Dennis explained that this is not an accurate comparison because DG customers use the Company's electric system to both receive and export energy, while non-DG

[85] See generally, *Goldstone v Bloomfield Twp Public Library*, 479 Mich 554, 568-69; 737 NW2d 476 (2007) and *Crego v Coleman*, 463 Mich 248, 258-59; 615 NW2d 218 (2000).

[86] See also the EPRI report titled "The Integrated Grid" (Exhibit A-34, Schedule X-5).

[87] The PFD did not indicate that it found any merit in suggestions that the SAC charge would somehow be illegal. The record further reflects that the Company's proposal complies with Michigan law and does not conflict with any federal law (8T 3649).

customers just use the system to receive energy. Thus, for example, energy efficiency customers reduce inflow and truly consume less energy, but a DG customer reduces inflow only when on-site generation is generating. Also, the on-site generation does not reduce the amount consumed on site (*i.e.* the amount the Company must be ready to serve at any point in time). (8T 3903-3904). Staff similarly recognized that "EWR is basically incapable of reducing a customer to no net load served by the utility" (8T 4233). This is a critical difference that creates a cost responsibility that cannot be ignored (8T 3668, 3673-74). Mr. Serna further explained that DG customers are different than voluntary demand response customers:

> For demand response, the risk is very low that the assumed capacity reductions will not occur as expected by DTE Electric. For distributed generation, the lack of specific performance requirements and lack of control by the Company makes it much less likely that a capacity contribution will be available at the time the Company needs it… [D]istributed generation customers under net metering have little to no incentive to manage their level and timing of power inflows and outflows, as their customer bills are essentially invariant to their level of onsite generation. Thus, there is also no incentive for a distributed generation customer to address equipment problems when there is no contribution to the utility's capacity requirements. [8T 3656-59].

In summary, the SAC appropriately seeks to recover costs that DG customers impose, and that would otherwise be shifted to non-DG customers. The SAC is also appropriately designed and supported by cost of service evidence. Therefore, it should be approved.

3. Michigan Law sets the requirements for the outflow credit.

DTE Electric proposed an outflow credit that is consistent with the first option provided by MCL 460.1177(4). Staff suggested a different interpretation of MCL 460.1177(4). The PFD found that other parties' proposals need not be discussed (PFD, p 274), and agreed with Staff, stating:

> The ALJ agrees with the Staff, that the plain language of MCL 460.1177(4), when read in its entirety, makes clear that the outflow credit, whatever [sic, whether?] based on LMP or power supply less transmission, applies only to *excess* generation above monthly consumption for the billing month (e.g., "the quantity of electricity generated and delivered to the utility distribution system by an eligible electric

> generator during the billing period [that] *exceeds* the quantity of electricity supplied from the electric utility *during the billing period* shall be credited[.]" The ALJ also agrees with Staff that subparts (a) and (b) describe alternate pricing mechanisms and that the language at the beginning of Section 177(4) cannot be ignored. Again, as DTE Electric asserts, every word and phrase of the statute must be given effect to avoid rendering any of the statute surplusage. Moreover, the ALJ finds that this interpretation of the statute does not conflict with Section 177(5), which only comes into play if "A charge for net metering and distributed generation customers [is] established pursuant to section 6a of 1939 PA 3, MCL 460.6a[.]" Because the SAC was rejected, Section 177(5) does not apply. Consistent with the analysis above, the Commission should approve the Staff's recommendation with respect to netting inflows and outflows. [PFD, pp 280-81. Emphasis in original.]

The PFD neglects that MCL 460.1177 generally concerns electric meters and billing, as stated in the title to that statute. MCL 460.1177(4) is specific with respect to the elements to be included in the outflow credit as follows:

> If the quantity of electricity generated and delivered to the utility distribution system by an eligible electric generator during a billing period exceeds the quantity of electricity supplied from the electric utility or alternative electric supplier during the billing period, the eligible customer shall be credited by their supplier of electric generation service for the excess kilowatt hours generated during the billing period. The credit shall appear on the bill for the following billing period and shall be limited to the total power supply charges on that bill. Any excess kilowatt hours not used to offset electric generation charges in the next billing period will be carried forward to subsequent billing periods. ***Notwithstanding any law or regulation, distributed generation customers shall not receive credits for electric transmission or distribution charges. The credit per kilowatt hours delivered into the utility's distribution system shall be either of the following***:
>
> (a) The ***monthly average real-time locational marginal price for energy at the commercial pricing node within the electric utility's distribution territory***, or for distributed generation customers on a time-based rate schedule, the monthly average real-time locational marginal price for energy at the commercial pricing node within the electric utility's distribution service territory during the time-of-use pricing period.
>
> (b) The electric utility's or alternative electric supplier's power supply component, excluding transmission charges, of the full retail rate during the billing period or time-of-use pricing period. (Emphasis added).

MCL 460.1177(5) further provides:

> A charge for net metering and distributed generation customers established pursuant to section 6a of 1939 PA 3, MCL 460.6a, ***shall not be reduced by any credit or other ratemaking mechanism*** for distributed generation under this section. (Emphasis added).

MCL 460.1177(4) plainly does not say what Staff proposed and the PFD now recommends. Instead, as set forth in the Company's briefs (Initial Brief pp. 148-151, Reply Brief pp. 215-219), the statute simply provides for a billing credit where there are "excess kilowatt hours generated during the billing period" instead of, for example, measuring on-site generation or providing that utilities must bill total inflow and send checks to customers for their total outflow. The second sentence of the statute states how the credit shall appear on bills, and further specifies that that the credit "***shall*** be limited to the total power supply charges on that bill." The statute then goes on to state that DG customers "***shall not*** receive "credits for electric utility transmission or distribution charges." [88] There is only one provision in the statute that addresses the outflow credit:

> The credit per kilowatt hours delivered into the utility's distribution system shall be either of the following:
>
> (a) The monthly average real-time locational marginal price for energy at the commercial pricing node within the electric utility's distribution territory, or for distributed generation customers on a time-based rate schedule, the monthly average real-time locational marginal price for energy at the commercial pricing node within the electric utility's distribution service territory during the time-of-use pricing period.
>
> (b) The electric utility's or alternative electric supplier's power supply component, excluding transmission charges, of the full retail rate during the billing period or time-of-use pricing period.

[88] MCL 460.1177(4)'s use of "shall" as well as the further use in MCL 460.1177(5) denotes a mandatory duty imposed by the Legislature and excludes the idea of administrative discretion. *Macomb Co Rd Comm'n v Fisher*, 170 Mich App 697, 700; 428 NW2d 744 (1988); *Southfield Twp v Drainage Bd*, 357 Mich 59, 76-77; 97 NW2d 281 (1959) ("the word 'shall' is mandatory and imperative and, when used in a command to a public official, it excludes the idea of discretion").

There is no mention of "excess kilowatt hours" as the PFD seems to suggest. Instead, the statute discusses "excess kilowatt hours" in the prior provisions regarding billing, but later, concerning the outflow credit, uses "kilowatt hours."

The Legislature plainly was drawing a distinction and intended that the credit is to be applied to "*kilowatt hours delivered into the utility's distribution system.*" The statute's plain language must be applied as written.[89] The Michigan Supreme Court also recently explained:

> Generally, when language is included in one section of a statute but omitted from another section, it is presumed that the drafters acted intentionally and purposely in their inclusion or exclusion. Similarly, "[c]ourts cannot assume that the Legislature inadvertently omitted from one statute the language that it placed in another statute, and then, on the basis of that assumption, apply what is not there." *People v Peltona*, 489 Mich 174, 186; 803 NW2d 140 (2011), quoting *Farrington v Total Petroleum, Inc*, 442 Mich 201, 210; 501 NW2d 76 (1993) (Emphasis added; footnote omitted).

Mr. Serna also discussed the language changes in Act 342 as they relate to net metering versus distributed generation (8T 3640-43). The table provided in Mr. Serna's testimony also provides a side-by-side comparison of the language in Act 342 and the corresponding sections of Act 295.

The PFD was also apparently persuaded to simply follow Staff's recommendation because the Commission addressed this issue in its April 18, 2018 Order in Case No. U-18383. The issue merits more consideration than it has received, however, and the current PFD/Staff position is contrary to statutory requirements, as indicated above. In Case No. U-18383, the Commission

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[89] *Elozovic v Ford Motor Co*, 472 Mich 408, 421-22, 425; 697 NW2d 851 (2005) ("The text must prevail. . . The Legislature is held to what it said. It is not for us to rework the statute. Our duty is to interpret the statute as written"); *Di Benedetto v West Shore Hosp*, 461 Mich 394, 402; 605 NW2d 300 (2000) ("we presume that the Legislature intended the meaning it clearly expressed - no further judicial construction is required or permitted, and the statute must be enforced as written"); *Hanson v Mecosta Co Road Comm'rs*, 465 Mich 492, 504; 638 NW2d 326 (2002); *Lorencz v Ford Motor Co*, 439 Mich 370, 376; 483 NW2d 844 (1992); *Ambs v Kalamazoo County Road Comm*, 255 Mich App 637, 650; 662 NW2d 424 (2003) ("where the language of a statute is clear, it is not the role of the judiciary to second-guess a legislative policy choice; a court's constitutional obligation is to interpret, not rewrite, the law").

recognized the arguments made by DTE Electric and Consumers Energy that MCL 460.1177(5) restricts the Commission from approving outflow credits from offsetting any distribution charges applied to inflow since those charges are intended to recover the COS pursuant to Act 341. The Commission found that "this prohibition is explicitly directed toward credits for the portion of outflow that exceeds inflow under the modified net metering billing method" (Case No. U-18383 April 18, 2018 Order, at 14-15) The U-18383 Order also stated that "[s]ection 177 does not apply to any DG billing method, such as the Inflow/Outflow billing mechanism, that implements a COS based tariff under Act 341, Section 6a(14)." (*Id.* at 15) However, if Section 177(5) was directed only at modified net metering customers, the statute would not have referenced both "net metering and distributed generation customers." Reading the term "distributed generation customers" out of Section 177(5) renders that term surplusage or nugatory in contradiction to defined statutory construction case law.[90] Moreover, the statute broadly refers to "***any*** credit or ratemaking mechanism" and not to a specific credit granted to modified net metering. In addition, Section 177(5) specifically refers to charges, "established pursuant to section 6a of 1939 PA 3, MCL 460.6a", and thus the U-18383 Order statement that Section 177 does not apply to any tariff under Act 341, Section 6a(14) is contrary to the language of Section 177.

Section 177(4) plainly says: "Notwithstanding any law or regulation, Distributed Generation customers shall not receive credits for electric utility transmission or distribution charges." The PFD/Staff's interpretation leaves unexplained how the broad and unlimited directive that "notwithstanding any law or regulation" distributed generation customers shall not receive credits for

[90] "Effect must be given to every word, phrase, and clause in a statute, and the court must avoid a construction that would render part of the statute surplusage or nugatory." *Book-Gilbert v Greenleaf*, 302 Mich App 538, 541; 840 NW2d 743 (2013); *Jenkins v Patel*, 471 Mich 158, 167; 684 NW2d 346 (2004) ("Courts must give effect to every word, phrase, and clause in a statute and avoid an interpretation that would render any part of the statute surplusage or nugatory")

electric utility transmission and distribution could somehow reasonably be interpreted as anything other than a universal restriction on such credits.

Section 177(5) also confirms that "any charge for net metering and distributed generation customers established under [MCL 460.6a] shall not be reduced by any credit or other ratemaking mechanism…" The PFD offers no analysis, but instead only states: "Moreover, the ALJ finds that this interpretation of the statute does not conflict with Section 177(5), which only comes into play if 'A charge for net metering and distributed generation customers [is] established pursuant to section 6a of 1939 PA 3, MCL 460.6a[.]' Because the SAC charge was rejected, Section 177(5) does not apply" (PFD, p 281). The PFD's conclusion does not withstand reasoned scrutiny. Section 177(5) contains no "if" qualification and does not refer to only certain situations in which it "comes in to play." If Section 177(5) was only to come in to play under certain situations, the legislature surely could have crafted it to say so. The plain reading of Section 177(5) states that a charge for distributed generation customers established pursuant to section 6a of 1939 PA 3, MCL 460.6a shall not be reduced by any credit or other ratemaking mechanism for distributed generation. To ignore this provision of the law by apparently suggesting no charges will be established pursuant to section 6a of 1939 PA 3, MCL 460.6a is flawed. Again, nowhere in the law does it suggest 177(5) only applies "if" a charge is established, it simply states, "a charge established". Public Act 342 of 2016 added this section to limit the amount of charges that can be reduced by any credit or ratemaking provision of the distributed generation program. The statutory language is clear. Indeed, it is hard to conceive of a clearer Legislative intention. Therefore, the PFD's recommendation should be rejected.

Moreover, Act 342 requires programs to be "cost effective" (MCL 460.1001(2)) and Act 341 requires that: "In establishing cost of service rates, the commission shall ensure that each class, or

sub-class, is assessed for its fair and equitable use of the electric grid." MCL 460.11. As proposed, DTE Electric's outflow credit model is consistent with MCL 460.1001(2), MCL 460.11 and MCL 460.1177(4).[91] The Legislature has also twice (once in 2008 PA 295 and again in 2016 PA 342) made clear that there cannot be credits for transmission or distribution associated with net metering and/or distributed generation.

Further, during examination by MEC/NRDC/SC, Company witness Serna also made it clear that customer credits apply to all generation delivered into the utility's distribution system:

> Q. O.K. And as I understand your testimony, you interpret credit to mean that any recognition of exports from a customer generator to the distribution grid falls within the meaning of credit. Is that fair?
>
> A. I believe that the, for the power that is delivered into the electric distribution system, I believe that to mean the Outflow rate, and that's why I believe that the Outflow rate should be set on any of these two options.
>
> Q. So my question is: Any outflow, if we're going to recognize that outflow from customer generator to distribution grid, we need to call that a credit? That's your premise; is that fair?
>
> A. I do believe that it is a credit. That the customer is getting a credit for that power that he is delivering to the distribution system, and as such deserves to receive some value for that power that he is delivering and a credit for that power that he's delivering to the system.
>
> Q. Is there any definition of the term credit that you're aware of that provides that definition that you're applying?
>
> A. When I read the legislation and look at the language on how it is structured and how I have analyzed, I do think that the word credit in this context -- I'm not being the legal expert -- indicates that for that power that is delivered, and under the proposed Inflow/Outflow method you have to apply a particular mechanism that

[91] In addition, the Legislature changed statutory language to remove the net metering references from section MCL 460.1177(4) and instead used the words "distributed generation," so that section does not simply apply to grandfathered net metering customers as has been suggested. The suggestion that the Company's interpretation would render the inflow/outflow model invalid similarly neglects that the applicable statutory language ("The credit per kilowatt hour for kilowatt hours delivered into the utility's distribution system shall be either of the following…") plainly indicates that the credits do not apply to generation used onsite. This plain language also reflects that the customer credit choices set forth in MCL 460.1177(4) apply to ALL kilowatt hours "delivered into the utility's distribution system," not just the net outflows (8T 3639-44).

> the Company is proposing from the Commission, it then does follow that it applies to that Outflow rate that we are proposing for that customer to be credited for. That's how I interpret the legislation, coupled with the proposal that we made in front of the Commission, and the concept of crediting those powers, that power delivery to the distribution system, at any of these two mechanisms. I will further say that that was what the Staff proposed. That was one of the two mechanisms, is what the Staff itself proposed as part of their rebuttal -- as part of their direct testimony, Mr. Ozar. (8T 3718-3719)

It also bears emphasis that the Legislature considered how electricity delivered to the utility's distribution system should be compensated and provided only two potential approaches: LMP (the Company's proposal) or power supply less transmission costs (Staff's proposal). If the Legislature believed that compensation for electricity delivered to the utility distribution system could be set differently or should continue to be debated (as some other parties have suggested), then the Legislature "surely could have said so."[92] It is also no mere coincidence that the two statutorily established options to compensate for power delivered to the electric distribution system do not include either a transmission or a distribution credit, which is consistent with the concept that there shall be no credit applied to transmission and/or distribution (8T 3647-48).

4. LMP is the appropriate choice for the outflow credit.

DTE Electric maintains that it is appropriate to use the LMP as the outflow credit because it provides cost-based compensation as it is the actual cost at which energy is traded on wholesale markets. The LMP is the market construct that most closely aligns with DG behavior, since DG customers make no commitment to DTE Electric regarding the volume or timing of their output (8T 3602. See generally, DTE Electric's Initial Brief, pp 151-54). Staff proposed to instead base

[92] *Lash v Traverse City*, 479 Mich 180, 189; 735 NW2d 628 (2007); *see also, People v McIntire*, 461 Mich 147, 160; 599 NW2d 102 (1999).

outflow compensation on the Company's power supply component less transmission costs (Staff Initial Brief, pp 100-102). The PFD agreed with Staff, stating in part:

> This PFD finds that the Staff's proposal for calculating the outflow credit, based on power supply less transmission is reasonable and well supported by the record. As the Staff points out, the company's outflow compensation based on LMP, as originally proposed, assumes that DG outflows have zero capacity value. [PFD, p 277.]

The Company is pleased that Staff proposed one of the two alternatives provided by the Legislature (discussed above), but disagrees with the PFD's recommendation, which is based on the proposition that DG customers should be viewed in the aggregate. As further discussed below, there is no data to support the proposition that distributed generation customers, on an aggregate basis, provide peak relief to the Company, and pointing to other jurisdictions provides no meaningful evidence with regard to DTE Electric's system (8T 3651-52).

Mr. Serna testified why using the LMP is an appropriate and predictable compensation method because there is only a 1 cent difference between on and off peak rates, and that the maximum price differential across three years was only $18.15, which when compared to the level of investment in a DG system seems negligible (8T 3662-3663). Additionally, when the final outflow is determined, the differentials decrease even further (8T 3663). Moreover, there is no avoided capacity value. As Mr. Serna pointed out, under DTE Electric's proposed tariff, distributed generation avoids the entire power supply portion of their bill (energy and capacity) for every kWh generated and used on site (8T 3651).

Mr. Serna's rebuttal testimony further explained why setting the outflow compensation at the real-time marginal LMP is the most appropriate methodology (8T 3650-55). For example, under the Company's proposal "distributed generation customers receive the capacity benefit for all the generation that is produced and consumed onsite" (8T 3651). He further observed that despite a

nearly year-long effort, the DG Workgroup led by Staff identified no data proving that DG customers provide peak relief to DTE Electric (8T 3651).[93] Witness Serna confirmed that behind the meter DG does not qualify for MISO capacity credits (8T 3653). Finally, Witness Serna correctly observed that DTE Electric has no temporal production contract with DG customers and no party has proposed that DG customers be subject to specific generation performance requirements:

> The commercial value of electric generation is, of course, significantly affected by the purchaser's ability to predict and rely upon proper and timely delivery of a specific amount of electric energy – and to be properly compensated when the seller fails to meet those expectations. DTE Electric is, of course, in the business of selling electric generation to retail electric consumers. Hence my point that a renewable-based, intermittently generating distributed generation customer that is likely not an electric generation expert or principally engaged in the activity of generating electricity provides relatively little assurance that it will operate its generation in a manner that furthers the Company's retail electric business. [8T 3656.]

Any outflow credit based on power supply less transmission could exceed the total power supply portion of a customer's bill. Exhibit A-42, Schedule FF1, illustrates how a customer taking service under the Company's proposed rates for Residential Time of Day Service Rate Schedule D1.2 (D1.2) could offset both power supply and distribution costs if the outflow credit was based on power supply less transmission rates.[94] This illustrates an additional reason why the Company's proposal to set the outflow credit equal to LMP and limit the application of outflow credit to the

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[93] Staff acknowledged this fact. (8T 3432)

[94] Exhibit A-42, Schedule FF1 shows a simplified bill calculation of a D1.2 customer with Rider 18 using the Company's proposed D1.2 rates and Staff's proposed Rider 18 methodology (bill reflects June-October pricing, and excludes surcharges). It assumes an on peak inflow of 100 kWh, an on peak outflow of 400 kWh, an off-peak inflow of 400 kWh, and an off-peak outflow of 100 kWh. Pursuant to Staff's proposal, the outflow credits are set equal to the power supply component of the D1.2 rate, less Staff's proposed D1.2 transmission rate. The Exhibit shows on line 22 that the total outflow credit is over $73, which offsets the entire power supply component of the bill (approximately $42 on line 14), and a major portion of the distribution component of the bill (line 18). The total bill in this example falls to $7.88 (line 23), which is less than even the Company's proposed service charge of $9.00 (line 16) (8T 3889).

power supply component of a customer's bill is both reasonable and complies with PA 342. Otherwise, a DG customer could just select whichever retail rate will maximize the outflow credit and potentially offset significant amounts of distribution charge (8T 3889-90).

After considering the various comments, the Company proposed an alternative where distributed generation customers could receive generation capacity credits in the outflow rate, but only if they sign up for the Company's Dynamic Peak Pricing ("DPP") rate, which is further discussed in DTE Electric's Initial Brief, pp 152-54. [95] The PFD observed that there appeared to be interest in the Company's alternative proposal, and that it should be explored in a future proceeding (PFD, pp 277-78). DTE Electric agrees if its approach to compensate outflow using LMP is adopted. The Company's proposal is a reasonable and prudent approach to provide a capacity credit, where no data exists to indicate that a capacity credit should be provided for these customers that are not providing any assurances to the Company that their generation output will be made available at the time and location needed in the Company's electric system.

The PFD states, "Staff's proposal for calculating the outflow credit, based on power supply less transmission is reasonable and well supported by the record. As the Staff points out, the company's outflow compensation based on LMP, as originally proposed, assumes that DG outflows have zero capacity value." (PFD, p 277) There is no explanation, however, as toTherthere how the Company's position is flawed and the PFD identifies no specific record evidence provided by Staff to support the notion that distributed generation outflow provides a capacity value equal

[95] Exhibit S-16.3 calculated the transmission unbundled rates for use in Staff's proposed DG tariff, and Staff indicated that these rates should either be shown on individual tariffs, or included within the DG tariff, and recalculated each case to ensure appropriate DG compensation (8T 4301). If the Commission approves Staff's proposed outflow compensation method (which would be inappropriate), then (to avoid unjustified burdens and complexity) the Company would support the alternative whereby the transmission rates would appear only on Rider 18, as opposed to each individual rate schedule. If Staff's proposal is accepted, the Company also agrees with Staff that the transmission rates should be recalculated in each general rate case (8T 3891-92).

to the full embedded cost of capacity present in power supply rates less transmission. In fact, Staff Witness Ozar appears to concede that there is no present evidence of any capacity value for DG. He testified that:

> Given that DTE's DG program is composed of multiple small end-users, and given the diversity of DG customers, it is reasonable for DTE to undertake a power-outflow study subsequent to implementation of the Inflow/Outflow tariff to confirm that the *coincident aggregate program* power-outflows are relatively stable, and predictable, irrespective of any *individual* DG customer's power output, and to quantify the effective DG outflow capacity and associated value. [8T 3431].

Thus, the record reflects that, while acknowledging a present lack of evidence and quantification of DG outflow capacity and associated value, Staff merely suggests that DTE Electric, nevertheless, compensate distributed generation customer outflow using the full power supply rate less transmission which results in a capacity value being paid to DG customers. Thus, the PFD's conclusion that Staff's positions in this regard are "reasonable and well supported by the record" cannot withstand scrutiny.

The PFD also recommends that, "the Commission should approve the Staff's recommendation with respect to netting inflows and outflows." (PFD p 281) The Company is somewhat confused with this finding and what it is intended to suggest, as Staff's proposed Distributed Generation Program does <u>not</u> propose to net inflow and outflows. Staff's proposed tariff (Staff Exhibit S-11.0) proposes that outflow, defined as the metered quantity of the customer's generation not used on site and exported to the utility, be credited, and that inflow, defined as the metered inflow delivered by the Company to the customer, be billed according to the retail rate schedule. Thus, the Company clarifies that Staff's proposed inflow/outflow methodology does not include netting inflows and outflows (this is further made clear in Staff's testimony, 8T 3423, 3436-7, and in Staff's Initial Brief.)

Finally, in regard to excess outflow credit balances, the PFD states, “The company’s position now is that customers moving out of their residences should receive a refund of any unused credit balance. However, customers who end their participation in the program and remain in the residence, will have any banked credits applied to future bills.” (PFD p. 287). This misstates the Company’s position on this matter, which was that customers moving out of their residence should forfeit any unused outflow credit, and that if a customer remained at the same residence that they should be able to continue to use their credit banks to offset power supply charges for up to twelve months (8T 3892)

The PFD recommends that the Company and Staff work together informally to find a mutually agreeable way to both provide information on the interconnection costs charged to DG customers that Staff requests (in some aggregated form perhaps) and protect customer privacy (PFD p. 287). While the Company appreciates the ALJ’s suggestion that the Company work together to achieve this reporting if Staff’s proposal to report on interconnection costs is accepted, the PFD did not mention several other concerns the Company has with Staff’s proposal. The proposed reporting will not achieve its intended purpose as a pricing signal to other developers, as interconnection costs will be highly dependent on the type of generation, size of the generator, the distance from existing DTE Electric facilities, and the location of the generator and its proximity to other generators on the system. The pricing signal would give an inaccurate picture of the actual costs that may be incurred at any given location (8T 3797). Furthermore, it is an unprecedented request that will raise the general cost to administer the DG program which would have to be passed along to all DTE Electric customers (8T 3798). Finally, the scope of the proposed reporting is unclear (8T 3796). Thus, Staff’s proposed reporting on interconnection costs should be rejected.

5. DTE Electric's proposal to limit the existing Standard Contract Rider DG to non-renewable generation should be approved.

Staff asserted that the Commission should not approve DTE Electric's proposal to limit the existing Standard Contract Rider No. DG to non-renewable types of generation. DTE Electric disagrees because there is no requirement for the Company to offer additional customer-owned renewable generation tariffs, such as Rider DG. 2016 Public Acts 341 and 342 contain explicit direction on creating a distributed generation program and tariff for customer-owned renewable generation, and the law outlines specific conditions under which customer owned renewable generation resources qualify for a distributed generation program. The Company is not presently choosing to provide additional programs at this time. Nevertheless, the PFD agreed with Staff's recommendation for a directive, stating:

> The PFD agrees with the Staff that Rider 14 (f/k/a Rider DG) should remain open to customers who do not qualify for Rider 16 or Rider 18. As discussed above, *Union Carbide* does not apply in this circumstance, in light of the fact that the issue concerns an existing tariff (and rate) which should be made available to customers who do not qualify for Rider 16 or Rider 18. Thus, except for the name change to Rider 14, the Rider DG tariff should not be revised or closed to additional renewable generators. [PFD, pp 288-89].

The PFD neglects the guidance of *Union Carbide v Public Service Comm*, 431 Mich 135; 428 NW2d 322 (1988), where our Supreme Court explained:

> The power to fix and regulate rates, however, does not carry with it, either explicitly or by necessary implication, the power to make management decisions.
>
> 'It must never be forgotten that while the State may regulate with a view to enforcing reasonable rates and rates, it is not the owner of the property of public utility companies and is not clothed with the general power of management incident to ownership.' *Missouri ex rel Southwestern Bell Telephone Co v Public Service Comm*, 262 US 276, 289; 43 S Ct 544, 547; 67 L Ed 981 (1923)." 431 Mich at 148-49. *See also Consumers Power Co v Public Service Comm*, 460 Mich 148, 157; 596 NW2d 126 (1999).

The PFD suggests that anything involving "an existing tariff (and rate)" is within the Commission's authority. Instead, the Commission's authority is limited. [96] The Commission has "ratemaking" authority; however, almost any aspect of DTE Electric's business the Commission regulates may affect rates to some degree, and the Commission cannot expand its authority by mischaracterizing its decision as "ratemaking." *See Consumers Power Co v Public Service Co*, 460 Mich 148, 157-58; 596 NW2d 126 (2004) (rejecting MPSC's "ratemaking" defense and vacating MPSC's order as unlawful).

DTE Electric is not presently choosing to provide additional programs, as indicated above. The Staff's contrary proposal (and now the PFD's recommendation) is inappropriate in the absence of the Company's agreement. The PFD recommendation to unilaterally change DTE Electric's program unlawfully encroaches on utility management, as illustrated by *Ford Motor Co v Public Service Comm*, 221 Mich App 370, 385, 387-88; 562 NW2d 224 (1997), where DTE Electric proposed a demand side management ("DSM") program. The Commission modified that proposed program. The Court of Appeals held that the Commission's modification of DTE Electric's DSM program was unlawful, explaining in part: "The PSC here exceeded its ratemaking authority by, in effect, requiring Detroit Edison's management to adopt the DSM program the PSC thought best. The PSC did significantly more than 'approve' the DSM program proposed by Detroit Edison." 562 NW2d at 234-234. See also *Attorney General v Public Service Comm*, 269 Mich App 473;

[96] The MPSC has no common law powers, but only possesses the limited authority that the Legislature conferred upon it. *Consumers Power Co v Public Service Comm,* 460 Mich 148, 155; 596 NW2d 126 (1999). The MPSC is an "administrative body created by statute and the warrant for the exercise of all its power and authority must be found in statutory enactments." *Union Carbide v Public Service Comm,* 431 Mich 135, 146; 428 NW2d 322 (1988); *Sparta Foundry Co v Public Utilities Comm*, 275 Mich 562, 564; 267 NW 736 (1936). The MPSC's authority must be conferred by clear and unmistakable statutory language, and a doubtful power does not exist. *Mason Co Civil Research Council v Mason Co,* 343 Mich 313, 326-27; 72 NW2d 292 (1955). The MPSC cannot expand its jurisdiction through its own acts or assumption of authority. *Ram Broadcasting v Public Service Comm,* 113 Mich App 79, 92; 317 NW2d 295 (1982). The MPSC cannot re-write the Legislature's language to include new or different provisions. *Hanson v Mecosta Co Rd Comm,* 465 Mich 492, 501-503; 638 NW2d 396 (2002). If an MPSC order conflicts with a statute, the order is void. *Manufacturers Nat'l Bank v DNR,* 420 Mich 128, 146; 362 NW2d 572 (1984).

713 NW2d 290 (2005) (MPSC exceeded its authority when it ordered the utility to expand its "green power" program and required customers who did not participate in the program to subsidize its costs).

6. Transition from Rider 16 to Rider 18.

DTE Electric proposes to add language to its existing net metering tariff, Rider 16, to state that Rider 16 will be unavailable for new customer on-site generation after the new DG program (Rider 18) is approved, unless the customer has submitted a completed Rider 16 application to the Company that is still pending before the Commission issues its order in this case (8T 3607-3608, 3877-78, 3900-01). Staff agreed with the Company's proposed language (Staff Initial Brief, p 141). The PFD agreed, but further recommended that "a customer who has an application filed with the utility before the effective date of the DG tariff may still be allowed to participate in net metering if the application is found deficient, provided the applicant cures the deficiency within 60 days" (PFD, p 291).

DTE Electric disagrees with the suggested 60 days to cure a deficiency because it would essentially invite incomplete applications to be submitted (contrary to the undisputed completion requirement) by providing another 60 days to cure that deficiency (the incompletion). DTE Electric maintains that its proposed language is appropriate. Mr. Mueller added that any new requirements necessary to make an application complete based upon DTE Electric's own rules would only apply going forward, and not to applications that had already been deemed complete. DTE Electric would also incorporate changes to interconnection requirements, the details of which presumably will be determined during the stakeholder process established in Case No. U-20344 (8T 3799).

For the reasons outlined above and further explained in DTE Electric's Initial and Reply Briefs and on the record, DTE Electric's Rider 18 and related DG proposals should be approved.

H. Retail Access Service Rider (RASR) changes.

DTE Electric proposes to change the Retail Access Service Rider ("RASR") (EC2) conditions for Retail Access Service (Electric Choice) customers to return to full service. The Company proposes that the less-restrictive return-to-service provisions now applicable to residential customers be implemented for all customers, since the more restrictive provisions now applicable to non-residential customers are no longer necessary. Mr. Bloch testified that the return-to-service provisions were established in 2004 to provide adequate planning time and ensure that returning customers did not cause undue power supply costs to be borne by other full-service customers. Subsequently, 2008 PA 286 established a 10% cap on Retail Access Service, which created stability in the Company's ability to plan for its customers' needs. The 10% cap was maintained by 2016 PA 341, which also introduced the State Reliability Mechanism ("SRM") to ensure reliable electric service and sufficient capacity resources to Michigan customers. A March 14, 2018 report in Case No. U-18441 reflects that all Alternative Electric Suppliers ("AESs") with customers participating in the Company's Retail Access Service program have demonstrated that they have sufficient capacity to serve all of their customers for the next four resource adequacy planning years (June 1, 2018 through May 31, 2022), so the Company will not be required to secure adequate capacity to serve these customers during this period. After May 31, 2022, if AESs are unable to secure adequate capacity for their customers, the SRM capacity charge is the appropriate mechanism to ensure that the Company's full-service customers are not subsidizing the capacity requirements of Retail Access Service customers (5T 1230-31).

The PFD instead agreed with Energy Michigan's proposal to retain both return-to-service option provisions (PFD, p 298). The Company disagrees. The Company's proposed changes are intended to simplify return to full service rules and for consistency and fairness have all full-service customers operate under the same minimum 12-month rate commitment specified in the

Company's tariff, Section C4.4. As a practical matter, keeping a short-term option provides no additional customer flexibility and costs the Company to maintain that option. Currently, any customer returning to full service who would like to take retail access service again must follow the allotment process as defined in the April 28, 2017 Order in Case No. U-15801 et al. DTE Electric reached its 10 percent cap on retail access service participation in November 2009 and few additional customers have been awarded an allotment to participate since then. Therefore, there is no need for a short-term return to full service provision as it provides no value to a customer, which is evident from the fact there are currently no customers taking Option 2 – Short-Term Service. Eliminating the short-term option would also eliminate any gaming concerns associated with short-term rate switching (5T 1259-60).

VII. REQUEST FOR RELIEF

DTE Electric respectfully requests that the Commission issue its final order in this case in accordance with the PFD as modified by the discussion above:

A. Granting DTE Electric's request for final rate relief, as further supported and explained in its Application, testimony, exhibits, Initial Brief (including Attachments A and B), Reply Brief (including Attachments A and B), and these Exceptions (including Attachments A and B) approving rates that will recover the Company's revenue deficiency of approximately $248.6 million, based on a May 1, 2019 through April 30, 2020 projected test year;

B. Approving an annual revenue increase effective as soon as possible in the projected test year;

C. Approving DTE Electric's proposed capital structure and return on equity;

D. Granting DTE Electric's request to implement an IRM and the associated reconciliation process proposed by the Company;

E. Granting DTE Electric's request for increased tree trimming expenditures, and the associated request for regulatory asset treatment and securitization;

F. Granting DTE Electric's request to reverse the previous ruling in Case No. U-18255 related to time of use rates, or alternatively allow the Company to implement the transition over a reasonable time period, and authorize deferral treatment and future recovery of the one-time operating expenses associated with the transition;

G. Approving the Company's proposed Weekend Flex and Weekend Bill pilot programs, and grant a waiver of the Commission's Residential Billing Rules R 460.125 and 460.121;

H. Approving the Company's proposed electric vehicle program;

I. Approving new rates effective as early as May 6, 2019 in the manner described in the Company's Application, testimony, exhibits, Initial Brief (including Attachments A and B), Reply Brief (including Attachments A and B); and these Exceptions (including Attachments A and B);

J. Granting DTE Electric's request to approve the PSCR base as requested by the Company;

K. Approving DTE Electric's proposals to implement certain customer rate schedules and tariffs;

L. Approving recovery of DTE Electric's generation investments;

M. Approving recovery of DTE Electric's investments related to the strengthening of the Company's distribution system and reliability improvements;

N. Approving recovery of DTE Electric's investments related to DSM, IT and Corporate Staff;

O. Approving a capacity charge based on the methodology proposed by the Company in this proceeding for calculating and applying the Capacity Charge Revenue Requirement;

P Granting any accounting authority associated with this case not already the subject of another application filed by the Company;

Q. Approving the remainder of DTE Electric's proposals and requested relief as set forth in the Company's Application, testimony, exhibits, Initial Brief (including Attachments A and B), Reply Brief (including Attachments A and B), and these Exceptions (including Attachments A and B; and

R. Granting such other lawful relief that the Commission deems reasonable and appropriate.

Respectfully submitted,

DTE ELECTRIC COMPANY

Andrea Hayden

Digitally signed by Andrea Hayden
Date: 2019.03.25 16:03:18 -04'00'

By:_______________________

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Dated: March 25, 2019

($000)

	(a)	(b)	(c)	(d)
Line No.	**Description**	**ALJ's Proposal For Decision**	**DTE Exceptions**	**Company's Exceptions Position**
1	Rate Base	$ 16,999,569	$ 152,779	$ 17,152,348
2				
3	Adjusted Net Operating Income	847,393	(45,656)	801,737
4				
5	Rate of Return	5.48%	0.237%	5.72%
6				
7	Income Requirements	931,614	49,106	980,720
8				
9	Income Deficiency (Sufficiency)	84,221	94,762	178,983
10				
11	Revenue Conversion Factor	1.3496		1.3496
12				
13	**Revenue Deficiency (Sufficiency)**	**$ 113,667**	**$ 127,894**	**$ 241,562**
14				
15	Tree Trim	0	7,053	7,053
16				
17	**Total Revenue Deficiency**	**$ 113,667**	**$ 134,948**	**$ 248,615**

($000)

	(a)	(b)	(c)		(d)
Line No.	**Description**	**ALJ's Proposal For Decision**	**DTE Exceptions**		**Company's Exceptions Position**
1	Plant in Service	$ 21,155,029	$ 159,344	(1)	$ 21,314,373
2	Plant Held for Future Use	57,923	-		57,923
3	Construction Work in Progress	1,679,418	-		1,679,418
4	Acquisition Adjustments	116,148	-		116,148
5	Total Utility Plant	$ 23,008,518	$ 159,344		$ 23,167,862
6					
7	Less: Depreciation Reserve	7,599,418	7,359	(2)	7,606,777
8					
9	Net Utility Plant	$ 15,409,100	$ 151,985		$ 15,561,085
10					
11	Net Capital Lease Property	6,222			6,222
12	Net Nuclear Fuel Property	112,164			112,164
13					
14	Total Utility Property and Plant	$ 15,527,486	$ 151,985		$ 15,679,471
15					0
16	Less: Capital Lease Obligations	6,324			6,324
17					
18	Net Plant	$ 15,521,162	$ 151,985		$ 15,673,147
19					
20	Allowance for Working Capital	1,478,407	794	(3)	1,479,201
21					
22	Rate Base	$ 16,999,569	$ 152,779		$ 17,152,348

Source Detail

(1) Plant in Service	Gross Amt	Rate Base Impact	
Contingency - Combined Cycle	10,533	8,217	PFD Appendix E
CHP	62,300	51,059	PFD Appendix E
Rouge River Unit 3	1,867	1,167	PFD Appendix E
Monroe Dry Fly Ash Processing	34,100	21,767	PFD Appendix E
Charging Forward	1,744	872	PFD Appendix E
Demand Side Mgmt (PCT)	9,593	7,880	PFD Appendix E
IT - Customer Service Projects	3,674	2,144	PFD Appendix E
IT Plant and Field Projects	3,180	1,846	PFD Appendix E
IT - Information Technology for IT projects	6,170	4,452	PFD Appendix E
Distribution Plant - Infrastructure redesign	50,524	42,890	PFD Appendix E
Corporate Staff - 2018 underspend	17,052	17,052	PFD Appendix E
		$ 159,344	

(2) Depreciation Reserve		
Contingency - Combined Cycle	120	PFD Appendix E
CHP	1,100	PFD Appendix E
Rouge River Unit 3	20	PFD Appendix E
Monroe Dry Fly Ash Processing	396	PFD Appendix E
Charging Forward	18	PFD Appendix E
Demand Side Mgmt (PCT)	1,607	PFD Appendix E
IT - Customer Service Projects	235	PFD Appendix E
IT Plant and Field Projects	227	PFD Appendix E
IT - Information Technology for IT projects	290	PFD Appendix E
Distribution Plant - Infrastructure redesign	1,654	PFD Appendix E
Corporate Staff - 2018 underspend	1,694	PFD Appendix E
	$ 7,359	

(3) Working Capital		
Charging forward regulatory asset	794	PFD Appendix E
	$ 794	

($000) | Page 3 of 4

Line No.	Description (a)	ALJ Proposal For Decision (b)		DTE Exceptions (c)			Company's Exceptions Position (d)	
	Operating Revenues							
1	Sales Revenues	$	4,695,905	$	-		$	4,695,905
2	Other Operating Revenue		90,345		-			90,345
3	Fuel and Purchased Power		1,385,795		-			1,385,795
4	Net Margin	$	3,400,455	$	-		$	3,400,455
5								
6	**Operating Expenses**							
7	Operations and Maintenance Expenses	$	1,259,482	$	50,289	(1)	$	1,309,771
8	Depreciation and Amortization		875,900		7,609	(2)		883,509
9	Property Taxes		275,525					275,525
10	Other Taxes		52,234					52,234
11	Other Income/Deductions		2,134					2,134
12	Total Operating Expenses	$	2,465,275	$	57,898		$	2,523,173
13								
14	**Operating Income**	$	935,180	$	(57,898)		$	877,282
15								
16	**Other Operating Income Adjustments**							
17	Allow. For Funds Used During Constr		34,896		(1,923)			32,973
18	Amortization of Loss on Reacquired Debt		(3,214)					(3,214)
19	Total Operating Income Adjustments	$	31,682	$	(1,923)		$	29,759
20								
21	**PreTax Net Operating Income**	$	966,862	$	(59,821)		$	907,041
22								
23	**Federal Income Taxes**		69,296		(10,769)			58,527
24	**State & Local Income Taxes**		50,173		(3,396)			46,777
25	**Net Operating Income**	$	847,393	$	(45,656)		$	801,737

Source Detail

(1) O&M detail

- River Rouge 3	PFD page 48		17,650	
- Inflation	PFD page 135		12,338	
- Incentive Compensation	PFD page 171		27,083	
- Uncollectibles	PFD page 154		234	
- Incremental charging forward	PFD page 213		1,168	
- Meter reading	PFD page 150		2,147	
- Weekend Flex / Fixed Bill	PFD page 173		1,408	
- EEI Dues	PFD page 174		1,269	
-Tree trim	PFD page 147		(13,007)	
	O&M Adj	**$**	**50,289**	

(2) Depreciation

Contingency - Combined Cycle	PFD Appendix E	158	
Monroe Dry Fly Ash	PFD Appendix E	653	
CHP	PFD Appendix E	35	
Rouge River Unit 3	PFD Appendix E	980	
Charging Forward	PFD Appendix E	36	
Demand Side Mgmt (PCT)	PFD Appendix E	1,576	
IT - Customer Service Projects	PFD Appendix E	429	
IT Plant and Field Projects	PFD Appendix E	369	
IT - Informaiton Technology for IT projects	PFD Appendix E	334	
Distribution Plant - Infrastructure redesign	PFD Appendix E	1,767	
Corporate Staff - 2018 Underspend	PFD Appendix E	1,270	
	Depreciation Adj	**7,609**	7,609

DTE Electric Company
Computation of Revenue Deficiency
Rate of Return Summary for April 30, 2020
Based on Average Rate Base

MPSC Case No. U-20162
Exceptions
Attachment A

Line No.	Description	Amount ($000)		Percent	Cost %	Weighted Cost % (1)	Weighted Cost %		
	ALJ's Proposal for Decision								
1	Long-Term Debt	$ 6,515,850	50.00%	37.94%	4.36%	2.18%	1.65%	1.0000	1.65%
2	Preferred Stock	0	0.00%	0.00%	0.00%	0.00%	0.00%	1.3496	0.00%
3	Common Shareholders' Equity	6,515,850	50.00%	37.94%	10.00%	5.00%	3.79%	1.3496	5.12%
4	Total	13,031,700	100.00%			7.18%			
5									
6	Short-Term Debt	112,875		0.66%	3.56%		0.02%	1.0000	0.02%
7									
8	Job Development - ITC - Debt	10,433		0.06%	4.36%		0.00%	1.0000	0.00%
9	Job Development - ITC Equity	10,858		0.06%	10.00%		0.01%	1.3496	0.0085%
10	Total Job Development - ITC	21,291							
11									
12	Deferred Income Taxes (Net)	4,006,648		23.33%	0.00%		0.00%		0.00%
13									
14	Total	17,172,514		100.00%			5.48%		6.81%
15									
	Company's Exceptions Position								
16	Long-Term Debt	$ 6,382,775	48.98%	37.17%	4.36%	2.13%	1.62%	1.0000	1.62%
17	Preferred Stock	0	0.00%	0.00%	0.00%	0.00%	0.00%	1.3496	0.00%
18	Common Shareholders' Equity	6,648,924	51.02%	38.72%	10.50%	5.36%	4.07%	1.3496	5.49%
19	Total	13,031,699	100.00%			7.49%			
20									
21	Short-Term Debt	112,875		0.66%	3.56%		0.02%	1.0000	0.02%
22									
23	Job Development - ITC - Debt	10,433		0.06%	4.36%		0.00%	1.0000	0.00%
24	Job Development - ITC Equity	10,858		0.06%	10.50%		0.01%	1.3496	0.01%
25	Total Job Development - ITC	21,291							
26									
27	Deferred Income Taxes (Net)	4,006,648		23.33%	0.00%		0.00%		0.00%
28									
29	Total	17,172,513		100.00%			5.72%		7.14%

DTE Electric Company
Revenue Requirement Adjustments to PFD
for the 12 Month Period Ending April 30, 2020
($000)

Line No.	(a) Description	(b) ALJ Proposal For Decision	(c) DTE Exceptions		(d) Company's Exceptions Position
1	**ALJ's Proposal for Decision**			$	113,667
2					
3	**Adjustments to Revenue Deficiency:**				
4					
5	**Capital Structure**				
6	- ROE - 10% versus 10.5%	(1)			44,889
7	- Debt/Equity - 50/50 versus 49/51				12,147
8			Rate Base		
9	**Rate Base - Net Plant**		Changes (2)		
10	- Contingency - Combined Cycle	Attachment A page 2	8,097		551
11	- CHP	Attachment A page 2	49,959		3,402
12	- Rouge River Unit 3	Attachment A page 2	1,147		78
13	- Monroe Dry Fly Ash Processing	Attachment A page 2	21,371		1,455
14	- Charging Forward	Attachment A page 2	854		58
15	- Demand Side Mgmt (PCT)	Attachment A page 2	6,274		427
16	- IT - Customer Service Projects	Attachment A page 2	1,909		130
17	- IT Plant and Field Projects	Attachment A page 2	1,619		110
18	- IT - Informaiton Technology for IT projects	Attachment A page 2	4,162		283
19	- Distribution Plant - Infrastructure redesign	Attachment A page 2	41,236		2,808
20	- Corporate Staff - 2018 underspend	Attachment A page 2	15,359		1,046
21			151,985		
22	**Rate Base -Working Capital**				
23	- Charging forward regulatory asset	Attachment A page 2	794		54
24					
25	**Operations and Maintenance Expenses**				
26	- River Rouge 3	Attachment A page 3			17,650
27	- Inflation	Attachment A page 3			12,338
28	- Incentive Compensation	Attachment A page 3			27,083
29	- Uncollectibles	Attachment A page 3			234
30	- Incremental charging forward	Attachment A page 3			1,168
31	- Meter reading	Attachment A page 3			2,147
32	- Weekend Flex / Fixed Bill	Attachment A page 3			1,408
33	- EEI Dues	Attachment A page 3			1,269
34	-Tree trim	Attachment A page 3			(13,007)
35					
36	**Depreciation and Amortization**	Attachment A page 3			7,609
37					
38	**AFUDC grossed up**	Attachment A page 3 x 1.3496			2,595
39					
40	**Tree Trim Revenue Requirement**	Exhibit A-11, Sch A1			7,053
41	Rounding				(37)
42					
43	**Total Adjustments to PFD Revenue Deficiency**	Line 6 through Line 41		$	134,948
44					
45	**Company's Exceptions Position**	Line 1 + Line 43		**$**	**248,615**

(1) PFD Rate Base $16,999 million x change in rate of return (0.272%) x revenue multiplier of 1.3496
(2) Rate Base Change multiplied by pre-tax return 6.81% (Attachment A p4)

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **DTE ELECTRIC COMPANY** for authority to increase its rates, amend its rate schedules and rules governing the distribution and supply of electric energy, and for miscellaneous accounting authority	)))))))	Case No. U-20162

PROOF OF SERVICE

STATE OF MICHIGAN)
) ss.
COUNTY OF WAYNE)

ESTELLA BRANSON, being duly sworn, deposes and says that on the 25th day of March, 2019, she served a copy of is DTE Electric Company's Exceptions to the Proposal for Decision, via electronic mail upon the persons referred to in the attached service list.

Estella R. Branson

Digitally signed by Estella R. Branson
Date: 2019.03.25 16:00:23 -04'00'

ESTELLA BRANSON

Subscribed and sworn to before
me this 25th day of March, 2019.

Lorri A. Hanner

Digitally signed by Lorri A. Hanner
Date: 2019.03.25 16:03:56 -04'00'

Lorri A. Hanner, Notary Public
Wayne County, MI (Acting in Wayne County)
My Commission Expires: April 20, 2020

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